Memorial Resource Development Corp.
Form 424B1
November 14, 2014
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Filed pursuant to Rule 424(b)(1)
Registration No. 333-199103

PROSPECTUS

30,000,000 Shares

Memorial Resource Development Corp.

Common Stock

$23.00 per share

MRD Holdco LLC and certain former management members of WildHorse Resources, LLC (collectively, the selling stockholders) are offering 30,000,000 shares of Memorial Resource Development Corp. s common stock. The selling stockholders have granted the underwriters a 30-day option to purchase up to an additional 4,500,000 shares of common stock. We will not receive any proceeds from the sale of shares by the selling stockholders, including any shares that the selling stockholders may sell pursuant to the underwriters option to purchase additional shares of common stock.

Our common stock is listed on the NASDAQ Global Select Market under the symbol MRD. We are a controlled company as defined under the NASDAQ listing rules because the group consisting of affiliates of Natural Gas Partners beneficially owns over 50% of our shares of outstanding common stock. See Principal and Selling Stockholders.

On November 12, 2014, the last reported sale price of our common stock on the NASDAQ Global Select Market was $23.53 per share.

Investing in our common stock involves risks that are described in the Risk Factors section beginning on page 23 of this prospectus.

We are an emerging growth company as that term is used in the Jumpstart Our Business Startups Act of 2012, and as such, we have elected to take advantage of certain reduced public company reporting requirements for this prospectus and future filings. See Risk Factors and Summary Emerging Growth Company Status.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

	Per Share	Total
Public Offering Price	$ 23.00	$ 690,000,000
Underwriting Discounts and Commissions(1)	$ 0.7475	$ 22,425,000
Proceeds, Before Expenses, to the Selling Stockholders	$ 22.2525	$ 667,575,000

(1) See Underwriting for a description of underwriting compensation payable in connection with this offering.

The underwriters expect to deliver the shares of common stock on or about November 18, 2014.

Joint Book-Running Managers

Citigroup **Barclays**
BofA Merrill Lynch **BMO Capital Markets** **Goldman, Sachs & Co.** **J.P. Morgan**
Raymond James **RBC Capital Markets** **Wells Fargo Securities**

Co-Managers

Credit Suisse	**Scotiabank / Howard Weil**	**Simmons & Company International**	**Stephens Inc.**
Stifel	**Wunderlich Securities**	**Credit Agricole CIB**	**Natixis**

The date of this prospectus is November 12, 2014.

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You should rely only on the information contained in this prospectus. Neither we, the selling stockholders, nor the underwriters have authorized any person to provide you with any information or represent anything about us or this offering that is not contained in this prospectus. If given or made, any such other information or representation should not be relied upon as having been authorized by us. The selling stockholders are not making an offer in any jurisdiction where an offer or sale is not permitted. The information contained in this prospectus is current only as of its date.

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Commonly Used Defined Terms

As used in this prospectus, unless we indicate otherwise:

- the Company, we, our, us and our company or like terms refer collectively to (i) Memorial Resource Development Corp. and its subsidiaries (other than MEMP and its subsidiaries) for periods after the restructuring transactions described below and (ii) our predecessor (as described below) other than MEMP and its subsidiaries for periods prior to the restructuring transactions;

- selling stockholders refers to MRD Holdco LLC and certain former management members of WildHorse Resources, LLC named herein;

- Memorial Production Partners, MEMP and the Partnership refer to Memorial Production Partners LP individually and collectively with its subsidiaries, as the context requires. We own the general partner of MEMP as well as 50% of MEMP s incentive distribution rights;

- MEMP GP refers to Memorial Production Partners GP LLC, the general partner of the Partnership, which we own;

- MRD Holdco refers to MRD Holdco LLC, a holding company controlled by the Funds that, together as part of a group owns a majority of our common stock;

- MRD LLC refers to Memorial Resource Development LLC, which historically owned our predecessor s business and was merged into MRD Operating LLC, our subsidiary, subsequent to our initial public offering;

- WildHorse Resources refers to WildHorse Resources, LLC, which owns our interest in the Terryville Complex and is our 100% owned subsidiary;

- our predecessor refers collectively to MRD LLC and its former consolidated subsidiaries, consisting of Classic Hydrocarbons Holdings, L.P., Classic Hydrocarbons GP Co., L.L.C., Black Diamond Minerals, LLC, Beta Operating Company, LLC, MEMP GP, BlueStone, MRD Operating LLC, WildHorse Resources, Tanos Energy LLC and each of their respective subsidiaries, including MEMP and its subsidiaries;

- the Funds refers collectively to Natural Gas Partners VIII, L.P., Natural Gas Partners IX, L.P. and NGP IX Offshore Holdings, L.P., which collectively control MRD Holdco;

- restructuring transactions means the transactions described beginning on page 11 that took place in connection with and shortly after the closing of our initial public offering, and pursuant to which we acquired substantially all of the assets of MRD LLC (not including its interests in BlueStone, MRD Royalty, MRD Midstream, Golden Energy Partners LLC or Classic Pipeline);

- BlueStone refers to BlueStone Natural Resources Holdings, LLC, a subsidiary of MRD Holdco that sold substantially all of its assets in July 2013 for approximately $117.9 million;

NGP refers to Natural Gas Partners, a family of private equity investment funds organized to make direct equity investments in the energy industry, including the Funds;

MRD Royalty refers to MRD Royalty LLC, a subsidiary of MRD Holdco that owns certain immaterial leasehold interests and overriding royalty interests in Texas and Montana;

MRD Midstream refers to MRD Midstream LLC, a subsidiary of MRD Holdco that owns an indirect interest in certain immaterial midstream assets in North Louisiana; and

Classic Pipeline refers to Classic Pipeline & Gathering, LLC, a subsidiary of MRD Holdco that owns certain immaterial midstream assets in Texas.

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data is

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also based on our good faith estimates. Although we believe these third-party sources are reliable and that the information is accurate and complete, neither we nor the selling stockholders have independently verified the information.

Equivalency

This prospectus presents certain production and reserves-related information on an "equivalency" basis. When we refer to oil and natural gas in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil and/or NGLs is equivalent to six Mcf of natural gas. This calculation is based on an approximate energy equivalency and does not imply or reflect a value or price relationship.

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SUMMARY

This summary highlights information appearing elsewhere in this prospectus. You should read the entire prospectus carefully, including Risk Factors beginning on page 23 and the historical and pro forma financial statements and the related notes to those financial statements. Certain oil and gas industry terms, including the terms proved reserves, probable reserves and possible reserves, used in this prospectus are defined in the Glossary of Oil and Natural Gas Terms in Appendix A of this prospectus.

Because we control MEMP through our ownership of its general partner, we are required to consolidate MEMP for accounting and financial reporting purposes even though we only own a minority of its limited partner interests. Our financial statements include two reportable business segments: (i) the MRD Segment, which reflects all of our operations except for MEMP and its subsidiaries, and (ii) the MEMP Segment, which reflects the operations of MEMP and its subsidiaries. Except with respect to our consolidated and combined financial statements or as otherwise indicated, the description of our business, properties, strategies and other information in this summary does not include the business, properties or results of operations of BlueStone, MRD Royalty, MRD Midstream and Classic Pipeline (the assets of which are included in our predecessor but were not conveyed to us in the restructuring transactions) or MEMP. Our proved reserves as of December 31, 2013 have been prepared by Netherland, Sewell & Associates, Inc., our independent reserve engineers (NSAI), and our probable and possible reserves as of December 31, 2013 have been prepared by our internal reserve engineers and audited by NSAI, all of which are reflected in our reserve reports (which we collectively refer to as our reserve report), summaries of which are included in Appendices B-1 and B-2 of this prospectus. Our proved reserves within the Terryville Complex as of September 30, 2014 have been prepared by NSAI (which we refer to as our recent reserve report), a summary of which is included in Appendix C of this prospectus.

Information expressed on a pro forma basis in this summary gives effect to certain transactions as if they had occurred on September 30, 2014 for pro forma balance sheet purposes and on January 1, 2013 for pro forma statements of operations purposes. For a description of these transactions, please read Summary Historical Consolidated and Combined Pro Forma Financial Data and Corporate History and Structure.

Overview

We are an independent natural gas and oil company focused on the exploitation, development, and acquisition of natural gas, NGL and oil properties with a majority of our activity in the Terryville Complex of North Louisiana, where we are targeting overpressured, liquids-rich natural gas opportunities in multiple zones in the Cotton Valley formation. As of December 31, 2013, our total leasehold position was 347,458 gross (205,818 net) acres, of which 60,041 gross (51,522 net) acres are in what we believe to be the core of the Terryville Complex. We are focused on creating shareholder value primarily through the development of our sizeable horizontal inventory. As of December 31, 2013, we had 1,582 gross (1,091 net) identified horizontal drilling locations, of which 1,431 gross (994 net) identified horizontal drilling locations are located in the Terryville Complex. These total gross identified horizontal drilling locations represent an inventory of over 42 years based on our expected 2014 drilling program. We believe our inventory to be repeatable and capable of generating high returns based on the extensive production history in the area, the results of our horizontal wells drilled to date, and the consistent reservoir quality across multiple target formations.

As of December 31, 2013, we had estimated proved, probable and possible reserves of approximately 1,126 Bcfe, 800 Bcfe and 1,711 Bcfe, respectively. As of such date, we operated 98% of our proved reserves, 71% of which were natural gas. For the nine months ended September 30, 2014, 56% of our pro forma MRD Segment revenues were attributable to natural gas production, 22% to NGLs and 22% to oil. For the nine months ended September 30, 2014, we generated pro forma MRD Segment Adjusted EBITDA of $259 million and pro forma net loss of $914 million, and made pro forma capital expenditures of $268 million. For the year ended

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December 31, 2013, we generated pro forma MRD Segment Adjusted EBITDA of $159 million and pro forma net loss of $2.9 million, and made pro forma total capital expenditures of $203 million. Please see Summary Historical Consolidated and Combined Pro Forma Financial Data Adjusted EBITDA for an explanation of the basis for the pro forma presentation and our use of Adjusted EBITDA to measure the MRD Segment s profitability.

Our average net daily production for the nine months ended September 30, 2014 was approximately 208 MMcfe/d (approximately 76% natural gas, 17% NGLs and 7% oil) and our reserve life was 14.8 years. The Terryville Complex represented 84% of our total net production for the nine months ended September 30, 2014. As of December 31, 2013, we produced from 95 horizontal wells and 800 vertical wells. Since January 1, 2014, in the Terryville Complex we have completed and brought online 21 horizontal wells through September 30, 2014, bringing our total number of producing horizontal wells to 41 in our primary formations.

The following chart provides information regarding our production growth and the increasing proportion of our horizontal well production since the beginning of 2012.

Our Properties

Cotton Valley Overview

The Cotton Valley formation extends across East Texas, North Louisiana and Southern Arkansas. The formation has been under development since the 1930s and is characterized by thick, multi-zone natural gas and oil reservoirs with well-known geologic characteristics and long-lived, predictable production profiles. Over 21,000 vertical wells have been completed throughout the play. In 2005, operators started redeveloping the Cotton Valley using horizontal drilling and advanced hydraulic fracturing techniques. To date, operators have drilled over 600 horizontal Cotton Valley wells. Some large, analogous redevelopment projects in the Cotton Valley include the Nan-Su-Gail Field in Freestone County, East Texas, where over 40 horizontal wells have been drilled by operators such as Devon Energy Corporation and Marathon Oil Corporation, and the Carthage

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Complex in Panola County, East Texas, where operators such as ExxonMobil Corporation, BP America, Memorial Production Partners LP and Anadarko Petroleum Corporation have drilled over 153 horizontal wells.

Cotton Valley Terryville Complex Horizontal Redevelopment

We are currently engaged in the horizontal redevelopment of the Terryville Complex in Lincoln Parish, Louisiana utilizing horizontal drilling and completion techniques similar to those employed at the Nan-Su-Gail Field, Carthage Complex in East Texas and other major resource plays across the United States. We have assembled a largely contiguous acreage position in the Terryville Complex of approximately 60,041 gross (51,522 net) acres as of December 31, 2013. The majority of our current and planned development is focused in and around what we believe to be the core of the Terryville Complex.

We entered the Terryville Complex via an acquisition from Petrohawk Energy Corporation in April 2010, with the goal of redeveloping the field with horizontal drilling and modern completion techniques. Since that acquisition, we have completed multiple bolt-on acquisitions and in-fill leases to build our current position. We believe the Terryville Complex, which has been producing since 1954, is one of North America s most prolific natural gas fields, characterized by high recoveries relative to drilling and completion costs, high initial production rates with high liquids yields, long reserve life, multiple stacked producing zones, available infrastructure and a large number of service providers.

After initially drilling eight vertical pilot wells in the Terryville Complex, we commenced a horizontal drilling program in 2011 to further delineate and define our position. In 2013, we shifted our operational focus to full-scale horizontal redevelopment of the Terryville Complex, going from two rigs to four rigs by the end of that year. Additionally, in the fourth quarter of 2013, we moved to drilling on multi-well pads that allow us to more efficiently drill wells and control costs as we develop our stacked pay zones. We intend to dedicate approximately $304 million of our $351 million drilling and completion budget in 2014 to develop multiple zones within the Terryville Complex, where we expect to drill 33 gross (29 net) horizontal wells and 3 gross (2.7 net) vertical wells. Our horizontal redevelopment program in the Terryville Complex will be focused on increasing our well performance and recoveries.

Within the Terryville Complex, as of December 31, 2013, we had 945 Bcfe, 688 Bcfe and 1,643 Bcfe of estimated proved, probable and possible reserves, respectively, and a drilling inventory consisting of 1,431 gross (994 net) identified horizontal drilling locations, including 91 gross (72 net) drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013. Since initiating our horizontal drilling program in 2011, we have drilled 44 gross (38 net) horizontal wells. Within the Terryville Complex, on a proved reserves basis, we operate approximately 99% of our existing acreage and hold an average working interest of approximately 74% across our acreage. Our high operating control allows us to more efficiently and economically manage the redevelopment of this extensive resource.

We believe seismic data, as well as information gathered from the results of our existing 275 vertical and 46 horizontal wells throughout the field, support the existence of at least ten stacked pay zones across the Terryville Complex. Our redevelopment program currently targets four of the stacked pay zones in the Cotton Valley formation zones we term the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink, all of which we are developing with horizontal wells through pad drilling. These four zones have an overall thickness ranging from 400 to 890 feet across our acreage position. We believe the overpressured nature of this section of the Cotton Valley formation is highly productive when accessed through horizontal drilling and fracture stimulation technologies. These qualities, when combined with the liquids-rich nature of the natural gas, high initial rates of production and competitive well costs, produce what we believe to be amongst the highest rate of return wells in the nation. Further, there are additional opportunities for redevelopment in the zones above the four main zones. NSAI has audited over $1 billion PV-10 and 677 Bcfe in our possible reserve category as of December 31, 2013 for the redevelopment of these additional zones. Please see Reserves.

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Our well results have shown consistency in initial production, decline rates and estimated ultimate recovery. The consistency of these results gives us confidence that the full-scale redevelopment of the Terryville Complex that we began in 2013 will continue to be successful. The table below details certain information on estimated ultimate recoveries and production on a gross basis for our 41 existing horizontal wells currently producing from our four primary target zones in the Terryville Complex to the extent such data is available as of the dates and for the periods presented below. The wells below highlight the consistency of our drilling results in the four primary target zones in which we plan to focus our future development activity.

			Producing Wells				Gross Wellhead Flow Rates After Processing (MMcfe/d)(2)(3)				
Well Name	**Lateral Length (Feet)**	**EUR (Bcfe)(1)**	**EUR Bcfe/ 1,000**	**First Production**	**Days Producing**	**Cumulative Production (Bcfe)**	**0-30**	**0-90**	**91-180**	**181-360**	**D&C ($MM)**
Upper Red											
LD Barnett 23H-2	4,015	12.3	3.1	1/30/2012	975	5.0	14.5	12.0	7.7	5.6	6.7
Colquitt 20 17H-1	4,357	11.5	2.6	7/30/2012	793	4.3	17.5	12.6	7.2	5.1	7.8
Dowling 22 15H-1	5,376	9.4	1.8	9/22/2012	739	5.7	16.3	15.6	11.1	8.2	8.8
Nobles 13H-1	4,216	9.1	2.1	11/17/2012	683	4.6	21.5	16.7	9.9	6.5	7.8
Sidney McCullin 16 21H-1	4,604	13.8	3.0	1/19/2013	620	5.0	17.4	14.2	10.8	8.4	8.1
Wright 14 11 HC-1	5,250	11.9	2.3	5/27/2013	492	5.5	19.6	18.1	16.1	8.4	8.8
BF Fallin 22 15H-1	5,122	12.3	2.4	6/17/2013	471	3.9	14.8	13.7	11.8	5.9	7.5
Dowling 20 17H-1	4,327	9.0	2.1	7/22/2013	436	2.6	15.2	11.0	5.7	4.5	10.7
Gleason 31H-1	3,692	2.4	0.7	8/12/2013	415	0.6	2.9	2.3	1.6	1.2	9.5
Burnett 26H-1	2,405	5.5	2.3	9/22/2013	374	1.2	6.9	5.6	3.5	2.4	6.9
Drewett 17 8H-1	4,010	15.6	3.9	11/13/2013	322	3.9	22.1	18.6	11.9		7.7
Wright 13 12 HC-2	6,009	24.0	4.0	12/21/2013	284	4.6	22.7	19.6	16.3		8.5
LA Minerals 15 22H-2	5,814	17.3	3.0	1/21/2014	253	3.4	17.8	16.1	13.4		8.8
Wright 13 24 HC-3	6,606	20.9	3.2	4/14/2014	170	3.4	30.3	24.6			10.8
Wright 13 24 HC-1	6,678	15.5	2.3	4/14/2014	170	2.8	25.0	20.4			11.8
TL McCrary 14 11 HC-5	5,875	30.0	5.1	4/14/2014	170	3.0	22.9	23.3			10.2
LA Minerals 19 30 HC-2	6,912	15.1	2.2	5/29/2014	125	2.3	25.1	20.4			10.8
LA Minerals 19 30 HC-1	6,519	19.6	3.0	6/1/2014	122	2.0	21.5	17.7			11.6
Werner 29H-1	3,410	4.7	1.4	8/13/2014	49	0.4	8.6				11.0
Werner 29 32 5 HC-1	6,810	9.7	1.4	8/13/2014	49	0.8	18.4				10.4
Werner 29 32 5 HC-2	8,300	16.5	2.0	8/13/2014	49	1.2	26.1				12.2
Temple 8H-1	2,403	6.3	2.6	8/24/2014	38	0.4	12.7				9.6
Temple 8 17 HC-1	6,210	2.9	0.5	8/29/2014	33	0.3	8.4				11.9
TL McCrary 14 11 HC-2	4,401	NA	NA	9/25/2014	6	0.1					7.7
TL McCrary 14 11 HC-4	4,810	NA	NA	9/25/2014	6	0.0					9.0
Lower Red											
TL McCrary 14H-1	4,544	12.7	2.8	5/1/2012	883	4.5	14.4	11.7	8.3	5.4	7.7
Nobles 13H-2	4,060	5.6	1.4	11/17/2012	683	3.3	16.0	11.9	8.2	5.2	7.8
LA Methodist Orphanage 14H-1	3,637	9.5	2.6	2/15/2013	593	4.0	13.9	13.0	9.7	6.3	9.1
Dowling 21 16H-1	4,590	8.4	1.8	3/18/2013	562	3.0	13.0	10.1	6.5	4.5	6.6
Drewett 17 8H-2	3,700	4.2	1.1	11/13/2013	322	1.2	8.7	6.2	3.2		7.0
Wright 13 12 HC-1	5,409	9.4	1.7	12/21/2013	284	2.2	14.7	11.4	7.2		9.3
LA Minerals 15 22H-1	5,926	8.1	1.4	1/21/2014	253	1.9	13.8	10.9	6.4		7.8
Wright 13 24 HC-4	6,518	15.1	2.3	4/14/2014	170	2.6	25.7	19.6			13.4
LA Minerals 19 30 HC-3	5,356	2.5	0.5	5/29/2014	125	0.6	8.8	5.9			12.1
LA Minerals 19 30 HC-4	6,469	3.5	0.5	6/1/2014	122	0.9	13.6	8.5			13.8
TL McCrary 14 11 HC-1	4,010	NA	NA	9/25/2014	6	0.0					8.9
TL McCrary 14 11 HC-3	4,620	NA	NA	9/25/2014	6	0.0					8.3
Lower Deep Pink Zone											
LA Methodist Orphanage 14H-2	3,550	6.1	1.7	2/15/2013	593	3.5	14.2	11.6	7.6	5.7	6.1
Wright 13 12 HC-4	5,010	5.8	1.2	12/21/2013	284	1.6	11.8	8.8	4.8		7.0
Wright 13 12 HC-3	5,706	5.4	0.9	12/21/2013	284	1.6	12.5	9.3	5.0		7.4
Upper Deep Pink Zone											
Werner 29 32 5 HC-3	6,679	3.1	0.5	8/13/2014	49	0.3	7.2				10.1
Averages(4)											
All Wells	**5,071**	**10.7**	**2.1**		**319**	**2.4**	**16.1**	**13.6**	**8.4**	**5.6**	**9.2**
Upper Red	**5,125**	**12.8**	**2.5**		**314**	**2.7**	**17.7**	**15.7**	**9.8**	**5.6**	**9.4**

Lower Red	**4,903**	**7.9**	**1.6**	**334**	**2.0**	**14.3**	**10.9**	**7.1**	**5.4**	**9.3**
Lower Deep Pink	**4,755**	**5.8**	**1.3**	**387**	**2.2**	**12.8**	**9.9**	**5.8**	**5.7**	**6.8**
Upper Deep Pink	**6,679**	**3.1**	**0.5**	**49**	**0.3**	**7.2**				**10.1**

(1) EUR represents the Estimated Ultimate Recovery or sum of total gross remaining proved reserves attributable to each location in our recent reserve report and cumulative sales from such location. EUR is shown on a combined basis for oil/condensates, gas and NGLs after the effects of processing.
(2) Production data is as of September 30, 2014 and shown gross on a combined basis after the effects of processing.
(3) Periodic flow rates start on day 4, with days 1 through 3 used to allow clean up associated with well completion. The 30-day flow rates therefore start on day 4 and continue 30 days to day 33 and the 90-day flow rates go from day 4 to day 93.
(4) We also have five horizontal producing wells outside of the four primary target zones. These averages do not include such wells.

Cotton Valley Terryville Complex Proved Reserves Update

As of September 30, 2014, within the core Terryville Complex, we had proved reserves of 849 Bcfe based on our recent reserve report, and an aggregate drilling inventory of 1,411 gross identified drilling locations, taking into account drilling activity during the first nine months of 2014. The PV-10 of our proved reserves within the Terryville Complex as of September 30, 2014 was $1.6 billion. PV-10 is a non-GAAP financial measure and differs from standardized measure, the most directly comparable GAAP financial measure. Please see Reserves. SEC pricing for natural gas and oil used in calculating the PV-10 of such proved reserves as of September 30, 2014 was $4.23 per Mcf and $95.56 per Bbl, respectively, based on the unweighted average of the first-day-of-the-month prices for each of the twelve months preceding September 2014.

East Texas

We own and operate approximately 54,337 gross (42,894 net) acres as of December 31, 2013 in Texas, where we are currently producing primarily from the Cotton Valley, Travis Peak and Bossier formations and targeting the Cotton Valley formation for future development. From January 1, 2011 through December 31, 2013, we have drilled and completed 28 gross (10.3 net) wells and are operating one rig in East Texas as of December 31, 2013. In 2014, we plan to invest $29 million to drill 4 gross (4 net) wells in East Texas in the Joaquin Field of Panola and Shelby Counties. As of December 31, 2013, we had approximately 108 gross identified horizontal drilling locations in East Texas, including 54 gross (43 net) drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013. For the nine months ended September 30, 2014, our average net daily production from our East Texas properties was 27 MMcfe/d, of which 75% was natural gas. Within our East Texas properties, on a proved reserves basis, we operate approximately 94% of our existing properties.

Rockies

We own approximately 162,375 gross (66,191 net) acres as of December 31, 2013 in our Rockies region and for the nine months ended September 30, 2014 our average net daily production from this region was 6 MMcfe/d. In 2014, we plan to invest $18 million to complete 2 gross (2 net) vertical wells in the Tepee Field of the Piceance Basin targeting the Mancos and Williams Fork formations. As of December 31, 2013, we had approximately 174 gross identified vertical drilling locations in the Tepee Field in our Rockies properties.

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Reserves

Our estimates of proved reserves are prepared by NSAI, and our estimates of probable and possible reserves are prepared by our management and audited by NSAI. As of December 31, 2013, we had 1,126 Bcfe, 800 Bcfe and 1,711 Bcfe of estimated proved, probable and possible reserves, respectively. As of this date, our proved reserves were 71% gas and 29% NGLs and oil. Additionally, the PV-10 of our proved reserves was $1,469 million, the PV-10 for our probable reserves was $1,052 million and the PV-10 for our possible reserves was $2,386 million. The following table provides summary information regarding our estimated proved, probable and possible reserves data by area based on our reserve report as of December 31, 2013 and our average net daily production by area for the nine months ended September 30, 2014:

	Proved Total (Bcfe)	% Gas	% Developed	Proved PV-10 (in millions)(1)	Probable Total (Bcfe)(2)	Probable PV-10 (in millions)(1)	Possible Total (Bcfe)(2)	Possible PV-10 (in millions)(1)	Average Net Daily Production (MMcfe/d)
Terryville Complex	945	71%	33%	$ 1,341	688	$ 1,032	1,643	$ 2,383	175
East Texas	175	75%	29%	110	109	18	66	3	27
Rockies	6	49%	100%	18	2	2	2	1	6
Total	1,126	71%	33%	$ 1,469	800	$ 1,052	1,711	$ 2,386	208

(1) In this prospectus, we have disclosed our PV-10 based on our reserve report. PV-10 is a non-GAAP financial measure and represents the period-end present value of estimated future cash inflows from our natural gas and crude oil reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using SEC pricing assumptions in effect at the end of the period. SEC pricing for natural gas and oil of $3.67 per Mcf and $93.42 per Bbl was based on the unweighted average of the first-day-of-the-month prices for each of the twelve months preceding December 2013. PV-10 differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes. Moreover, GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves. Because PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized estimates of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Nonetheless, we believe that PV-10 estimates for reserve categories other than proved present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. In addition, investors should be cautioned that estimates of PV-10 for probable and possible reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Our PV-10 estimates of proved reserves and our standardized measure are equivalent as of December 31, 2013 because, prior to the completion of our initial public offering, we were not subject to entity level taxation. Accordingly, no provision for federal income taxes has been provided because taxable income for 2013 was passed through to our equity holders. However, had we not been a tax exempt entity as of December 31, 2013, our estimated discounted future income tax in respect of our proved, probable and possible reserves would have been approximately $401 million, $368 million and $835 million, respectively. Since the closing of our initial public offering, we are treated as a taxable entity for federal income tax purposes and our future income taxes will be dependent upon our future taxable income. Neither PV-10 nor standardized measure represents an estimate of fair market value of our natural gas and oil properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of estimated reserves held by companies without regard to the specific tax characteristics of such entities.

(2) Substantially all of our estimated probable and possible reserves are classified as undeveloped.

Drilling Inventory and Capital Budget

We intend to develop our multi-year drilling inventory by utilizing our significant expertise in horizontal drilling and fracture stimulation to grow our production, reserves and cash flow. For 2014, we have budgeted a total of $351 million to drill 39 gross (34 net) operated horizontal wells. We expect to fund our 2014 development primarily from cash flows from operations. The majority of our drilling locations and our 2014 development program are focused on the Terryville Complex, where we plan to invest $304 million on drilling 33 gross (29 net) horizontal wells and 3 gross (2.7 net) vertical wells. In East Texas, we plan to invest $29 million on drilling and completing 4 gross (4 net) horizontal wells. In the Rockies, we plan to invest $18 million on completing 2 gross (2 net) vertical wells in the Tepee Field.

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The following table provides information regarding our acreage and drilling locations by area as of December 31, 2013:

	Net Acreage	WI%	Gross Horizontal Drilling Locations(1)(2)(3) Proved	Probable	Possible	Management	Total Gross	Total Net	Gross Horizontal Drilling Inventory (years)
Terryville Complex	96,733	74%	91	147	450	743	1,431	994	43
East Texas	42,894	79%	54	39	15		108	92	27
Rockies	66,191	41%		23	20		43	4	
Total	205,818	59%	145	209	485	743	1,582	1,091	42

(1) The above table excludes 192 proved vertical drilling locations in our reserve report in the Terryville Complex and 174 identified vertical locations based on management estimates in the Rockies.
(2) Please see Business Our Operations Drilling Locations for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see Risk Factors Risks Related to Our Business Our identified drilling locations, which are scheduled out over many years, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. Proved, probable and possible locations are based on our reserve report. Management locations are based on management estimates of additional identified drilling locations.
(3) As of September 30, 2014, we had an aggregate drilling inventory of 1,411 identified gross horizontal inventory locations in the Terryville Complex, taking into account drilling activity during the first nine months of 2014. Please see Our Properties Cotton Valley Terryville Complex Proved Reserves Update.

Our extensive inventory and horizontal drilling program in the Terryville Complex is currently focused on four zones within the Cotton Valley formation the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. The table below sets forth our drilling locations by zone as of December 31, 2013 along with the average results for the wells we have drilled within each zone. Please see Business Our Properties Cotton Valley Terryville Complex Horizontal Redevelopment for more detail on our properties in the Terryville Complex and the table on page 99 for the 30 day initial production rate and EUR condensate volumes.

Lower Cotton Valley Zone	Gross Horizontal Drilling Locations(1)(4) Proved	Probable	Possible	Management	Total	Average Historical Results(2) Producing Wells Drilled(1)	EUR (Bcfe)(3)	Drilling and Completion Costs ($MM)
Upper Red	47	42	40	313	442	25	12.8	$ 9.4
Lower Red	40	40	36	276	392	12	7.9	9.3
Lower Deep Pink	4	28	47	79	158	3	5.8	6.8
Upper Deep Pink		37	42	75	154	1	3.1	10.1
Other Zones			285		285			
Total Terryville Complex	91	147	450	743	1,431	41	10.7	$ 9.2

(1) Please see Business Our Operations Drilling Locations for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see Risk Factors Risks Related to Our Business Our identified drilling locations, which are scheduled out over many years, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. Proved, probable and possible locations are based on our reserve report. Management locations are based on management estimates of additional identified drilling locations.
(2) Relates to the 41 horizontal wells drilled by us in the four primary target zones in the Terryville Complex and included in our recent reserve report as proved developed reserves as of September 30, 2014.
(3) EUR represents the Estimated Ultimate Recovery or the sum of total gross remaining proved reserves attributable to each location in our recent reserve report and cumulative sales from such location. EUR is shown at the wellhead on a combined basis for oil/condensates and wet gas.
(4)

As of September 30, 2014, we had an aggregate drilling inventory of 1,411 identified gross horizontal inventory locations in the Terryville Complex, taking into account drilling activity during the first nine months of 2014. Please see Our Properties Cotton Valley Terryville Complex Proved Reserves Update.

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Our Terryville horizontal development program in 2014 has an average working interest of 86% and our total horizontal development inventory has an average working interest of 69%.

For the Terryville Complex, our 2014 budget assumes an average drilling and completion cost of $9.5 million for gross horizontal wells ($8.3 million per net well) and is based on an average lateral length of 5,824 feet. As part of our long-term development plan, the lateral length of our planned wells is expected to increase and we expect wells within the Terryville Complex to increase to a 7,500 foot lateral length.

Business Strategies

Our primary objective is to build shareholder value through growth in reserves, production and cash flows by developing and expanding our significant portfolio of drilling locations. To achieve our objective, we intend to execute the following business strategies:

***Grow production, reserves and cash flow through the development of our extensive drilling inventory*.** We believe our extensive inventory of low-risk drilling locations, combined with our operating expertise, will enable us to continue to deliver production, reserve and cash flow growth and create shareholder value. As of December 31, 2013, we had assembled an aggregate drilling inventory of 1,582 gross identified horizontal drilling locations, 90% of which are in the Terryville Complex, representing a drilling inventory of over 43 years based on our expected 2014 drilling program. We believe that the risk and uncertainty associated with our core acreage positions in the Terryville Complex has been largely reduced through our development activity, and because those positions are in areas with extensive drilling and production history. Since initiating our horizontal drilling program with one rig in 2011, we have invested over $521 million in the Terryville Complex through September 30, 2014. With six rigs running in the Terryville Complex as of September 30, 2014, we are one of the most active drillers in the Cotton Valley formation. We intend to dedicate approximately $304 million of our $351 million drilling and completion budget in 2014 to develop the overpressured liquids-rich Terryville Complex through multi-well pad drilling. We believe multiple vertically stacked producing horizons in the Terryville Complex can be developed using horizontal drilling techniques, thus enhancing the economics of this field.

***Enhance returns through prudent capital allocation and continued improvements in operational and capital efficiencies*.** We continually monitor and adjust our drilling program with the objective of achieving the highest total returns on our portfolio of drilling opportunities. We believe we will achieve this objective by (i) minimizing the capital costs of drilling and completing horizontal wells through knowledge of the target formations, (ii) maximizing well production and recoveries by optimizing lateral length, the number of frac stages, perforation intervals and the type of fracture stimulation employed, (iii) targeting specific zones within our leasehold position to maximize our hydrocarbon mix based on the existing commodity price environment and (iv) minimizing operating costs through efficient well management.

***Exploit additional development opportunities on current acreage*.** Our existing asset base provides numerous opportunities for our highly experienced technical team to create shareholder value by increasing our inventory beyond our currently identified drilling locations and ultimately by growing our estimated proved reserves. In the Terryville Complex, we are currently targeting multiple stacked horizons. We also believe our East Texas region has a significant inventory of low-risk, liquids-rich horizontal drilling locations. Finally, we continue to evaluate our leasehold positions in the Rockies and have preliminarily identified over 170 potential vertical locations.

***Maintain a disciplined, growth oriented financial strategy*.** We intend to fund our growth primarily with internally generated cash flows while maintaining ample liquidity and access to the capital markets. Furthermore, we plan to hedge a significant portion of our expected production to reduce our exposure to downside commodity price fluctuations and enable us to protect our cash flows and maintain liquidity to fund our drilling program.

Since approximately 76% of our acreage in the Terryville Complex was held by production as of December 31, 2013 and no significant drilling commitments are needed to hold our remaining acreage in the near term, we are able to allocate capital among projects in a manner that optimizes both costs and returns, resulting in a highly efficient drilling program.

***Make opportunistic acquisitions that meet our strategic and financial objectives*.** We will seek to acquire oil and gas properties that we believe complement our existing properties in our core areas of operation. In addition to our focus on the Terryville Complex, we are pursuing other properties that provide opportunities for the addition of reserves and production through a combination of exploitation, development, high-potential exploration and control of operations. We follow a technology driven strategy to establish large, contiguous leasehold positions in the core of prolific basins and opportunistically add to those positions through bolt-on acquisitions over time. We entered into the Terryville Complex through strategic acquisitions and grassroots leasing efforts, amassing a land position as of December 31, 2013 of 96,733 net acres, 51,522 net acres of which we believe to be in the core of the play. We will continue to identify and opportunistically acquire additional acreage and producing assets to complement our multi-year drilling inventory.

Competitive Strengths

We believe that the following strengths will allow us to successfully execute our business strategies.

***Large, concentrated position in one of North America s leading plays*.** As of December 31, 2013, we owned approximately 60,041 gross (51,522 net) acres in what we believe to be the core of the Terryville Complex in Lincoln Parish, which we believe to be one of North America s most prolific liquids-rich natural gas fields, characterized by consistent and predictable geology and multiple stacked pay formations confirmed by extensive vertical well control. Through September 30, 2014, our drilling program in the Terryville Complex has produced some of the top performing gas wells in the United States in the previous two years, with single horizontal well results having achieved EURs averaging 10.7 Bcfe per well. Through September 30, 2014, we have brought 41 wells online within our four primary target zones with average 30-day initial production rates of 16.1 MMcfe/d and average drilling and completion costs of $9.2 million per well. Approximately 76% of our acreage in the Terryville Complex was held by production at December 31, 2013 and there are no significant lease expirations until 2017. Additionally, all of our acreage in this play can be held by running a one-rig program over the next 18 months.

***De-risked acreage position with multi-year inventory of liquids-rich drilling opportunities*.** As of December 31, 2013, we had a drilling inventory consisting of 1,582 gross identified horizontal drilling locations, of which approximately 145 are gross proved undeveloped locations. Based on our expected 2014 drilling program and gross identified drilling locations, we have over 42 years of liquids-rich drilling inventory. The majority of our drilling activity has been and will continue to be focused in the Terryville Complex, where we produce liquids-rich natural gas from the overpressured Cotton Valley formation. We have used subsurface data from our vertical wells coupled with 3-D seismic data to identify and prioritize our inventory based on returns. This liquids-rich gas formation allows for NGL processing that, when coupled with the condensate produced, results in strong well economics. For the nine months ended September 30, 2014, 56% of our MRD Segment revenues were attributable to natural gas, 22% to NGLs and 22% to oil.

***Significant operational control with low cost operations*.** On a proved reserves basis, we operate 99% of our properties and have operational control of all of our drilling inventory in the Terryville Complex. We believe maintaining operational control will enable us to enhance returns by implementing more efficient and cost-effective operating practices, through the selection of economic drilling locations, opportunistic timing of development, continuous improvement of drilling, completion and stimulation techniques and development on multi-well pads. As a result of the contiguous nature of our leasehold in the Terryville Complex, its geologic continuity and cross unit lateral pooling, we are able to drill consistently long laterals, averaging over 5,071

lateral feet, which helps us to reduce costs on a per-lateral foot basis and increase our returns. We expect the average lateral length of the 33 gross wells that we expect to drill in the Terryville Complex in 2014 to be 5,824 feet per well. Operating in mature basins in North Louisiana and East Texas allows us to take advantage of the available and extensive midstream infrastructure and accelerate our development plan without encountering significant constraints in either takeaway or processing capacity. Our operational control allows us to focus on operating efficiency, which has resulted in our MRD Segment lease operating costs declining 35% from $0.50 per Mcfe for the nine months ended September 30, 2013 to $0.33 per Mcfe for the nine months ended September 30, 2014.

Proven and incentivized executive and technical team. We believe our management and technical teams are one of our principal competitive strengths due to our team s significant industry experience and long history of working together in the identification, execution and integration of acquisitions, cost efficient management of profitable, large scale drilling programs and a focus on rates of return. Additionally, our technical team has substantial expertise in advanced drilling and completion technologies and decades of expertise in operating in the North Louisiana and East Texas regions. The members of our management team collectively have an average of 22 years of experience in the oil and natural gas industry. John A. Weinzierl, our Chief Executive Officer, has 24 years of oil and natural gas industry experience as a petroleum engineer, a strong commercial and technical background and extensive experience acquiring and managing oil and natural gas properties. Our management team has a significant economic interest in us directly and through its equity interests in our controlling stockholder, MRD Holdco. We believe our management team is motivated to deliver high returns, create shareholder value and maintain safe and reliable operations.

Our relationship with MEMP. We own a 0.1% general partner interest in MEMP through our ownership of its general partner as well as 50% of MEMP s incentive distribution rights. MEMP s objective as a master limited partnership is to generate stable cash flows, allowing it to make quarterly distributions to its limited partners and, over time, to increase those quarterly distributions. As a result of its familiarity with our management team and our asset base and our track record of prior drop-down transactions, we believe that MEMP is a natural purchaser of properties from us that meet its acquisition criteria. We believe this mutually beneficial relationship enhances MEMP s ability to generate consistent returns on its oil and natural gas properties, provides us with a growing source of cash flow from our partnership interests in MEMP and allows us to monetize producing non-core properties. Since MEMP s initial public offering, we have consummated drop-down transactions with MEMP totaling approximately $391 million. In addition, we may have the opportunity to work jointly with MEMP to pursue certain acquisitions of oil and natural gas properties that may not otherwise be attractive acquisition candidates for either of us individually. While we believe that MEMP would be a preferred acquirer of our mature, non-core assets, we are under no obligation to offer to sell, and it is under no obligation to offer to buy, any of our properties.

Financial strength and flexibility. During 2013, we generated $159 million of pro forma MRD Segment Adjusted EBITDA and made pro forma total capital expenditures of $203 million. During the nine months ended September 30, 2014, we generated pro forma MRD Segment Adjusted EBITDA of $259 million and made pro forma capital expenditures of $268 million. We intend to continue to fund our organic growth predominantly with internally generated cash flows while maintaining ample liquidity for opportunistic acquisitions. We will continue to maintain a disciplined approach to spending whereby we allocate capital in order to optimize returns and create shareholder value. We seek to protect these future cash flows and liquidity levels by maintaining a three-to-five year rolling hedge program. As of September 30, 2014, our total liquidity, consisting of cash on hand and available borrowing capacity under our revolving credit facility, was approximately $650.2 million.

Initial Public Offering and Recent Developments

On June 18, 2014, we completed our initial public offering of 49,220,000 shares of common stock at a price to the public of $19.00 per share. Of the 49,220,000 shares offered, 21,500,000 were offered by us and 27,720,000 were offered by the selling stockholder, MRD Holdco. We did not receive any proceeds from the sale of shares by MRD Holdco. We used the net proceeds of approximately $380.2 million from our sale of shares in our initial public offering (i) to redeem the 10.00%/10.75% Senior PIK toggle notes due 2018 (the PIK notes) issued by MRD LLC in their entirety and to pay the applicable premium in connection with such redemption and accrued and unpaid interest to the date of redemption, (ii) together with borrowings of approximately $614.5 million under our $2.0 billion revolving credit facility entered into in connection with the closing of our initial public offering, to make a cash payment to certain former management members of WildHorse Resources in connection with their contribution to us of their membership interests and incentive units in WildHorse Resources, (iii) to repay borrowings outstanding under WildHorse Resources revolving credit facility and second lien term loan, which we refer to collectively as WildHorse Resources credit agreements, (iv) to reimburse MRD LLC for interest paid on the PIK notes and (v) to pay costs associated with our revolving credit facility.

On July 10, 2014, we completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes (the MRD Senior Notes) at par. The MRD Senior Notes will mature on July 1, 2022. Interest on the MRD Senior Notes accrues from July 10, 2014 and will be payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2015. The net proceeds of approximately $586.0 million, after deducting the initial purchasers discounts and commissions and offering expenses, were used to repay a portion of the borrowings outstanding under our revolving credit facility. The amounts to be repaid under our revolving credit facility were incurred to repay the amounts outstanding under WildHorse Resources credit facilities in connection with the closing of our initial public offering. In conjunction with the closing of the offer and sale of the MRD Senior Notes, the borrowing base under our revolving credit facility was automatically decreased by $56.5 million.

On November 4, 2014, our wholly-owned subsidiary, Terryville Mineral & Royalty Partners LP (TRVL), filed a registration statement on Form S-1 with the SEC in connection with its proposed initial public offering of common units representing limited partner interests. In connection with the closing of the proposed offering, we will contribute to TRVL certain overriding royalty interests in approximately 27,000 gross acres in the Terryville Complex in exchange for limited partner interests in TRVL. The royalty interests will entitle TRVL to receive 7% of gross revenues from production within such acreage on all of our existing horizontal producing wells and future wells completed by us. TRVL intends to distribute the net proceeds from the proposed offering to us. A registration statement relating to these securities has been filed with the SEC but has not yet become effective. These securities may not be sold nor may any offers to buy be accepted prior to the time the registration statement becomes effective, and this prospectus does not constitute an offer to sell or a solicitation of any offers to buy these securities.

Acquisition History

We built out our leasehold positions in North Louisiana, East Texas and the Rocky Mountains primarily through the following acquisition activities:

- In November 2007, we acquired interests in the Joaquin Field, which is the core of our East Texas acreage;
- In December 2007, we acquired interests in the Tepee Field in the Piceance Basin in Colorado;
- In April and May 2010, we acquired interests in the Terryville Complex and other North Louisiana fields, which are the core of our North Louisiana acreage;

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In November 2010, we acquired interests in the Spider and E. Logansport Fields in North Louisiana;

In May 2012, we acquired interests in the Terryville Complex and Double A Field in North Louisiana and East Texas;

In April 2013, we acquired interests in the West Simsboro and Simsboro Fields of the Terryville Complex in North Louisiana;

In November 2013, we acquired the remaining equity interests in Classic Hydrocarbons Holdings, L.P., Classic Hydrocarbons GP Co., L.L.C. and Black Diamond Minerals, LLC, which hold oil and natural gas properties in East Texas, North Louisiana and the Rocky Mountains; and

In February 2014, we repurchased net profits interests in the Terryville Complex from an affiliate of NGP for $63.4 million after customary adjustments. These net profits interests were originally sold to the NGP affiliate upon the completion of certain acquisitions in 2010 by WildHorse Resources.

Our Principal Stockholder

Our principal stockholder is MRD Holdco, which is controlled by the Funds, which are three of the private equity funds managed by NGP. Upon completion of this offering, MRD Holdco, one of the selling stockholders in this offering, will own approximately 40% of our common stock (or approximately 38% if the underwriters option to purchase additional shares from the selling stockholders is exercised in full). Pursuant to a voting agreement, MRD Holdco also has the right to direct the vote of an additional approximately 18% of our common stock (or approximately 18% if the underwriters option to purchase additional shares from the selling stockholders is exercised in full) owned by certain former management members of WildHorse Resources (including the other selling stockholders). The Funds also collectively indirectly own 50% of MEMP s incentive distribution rights, and MRD Holdco owns 5,360,912 subordinated units of MEMP, representing an approximate 6.2% limited partner interest in MEMP. We are also a party to certain other agreements with MRD Holdco, the Funds and certain of their affiliates. For a description of the voting agreement and these other agreements, please read Certain Relationships and Related Party Transactions.

Founded in 1988, NGP is a family of private equity investment funds, with cumulative committed capital of over $14.5 billion since inception, organized to make investments in the natural resources sector. NGP is part of the investment platform of NGP Energy Capital Management, a premier investment franchise in the natural resources industry, which together with its affiliates has managed over $17 billion in cumulative committed capital since inception.

Our Interest in Memorial Production Partners LP

Through our ownership of its general partner, we control MEMP. We also own 50% of its incentive distribution rights. MEMP is a publicly traded limited partnership engaged in the acquisition, exploitation, development and production of oil and natural gas properties in the United States, with assets consisting primarily of producing oil and natural gas properties that are located in East Texas/North Louisiana, the Rockies, South Texas, the Permian and offshore southern California. Most of MEMP s properties are located in large, mature oil and natural gas reservoirs with well-known geologic characteristics and long-lived, predictable production profiles and modest capital requirements. Because we control MEMP, we are required to consolidate MEMP for accounting and financial reporting purposes, even though we and MEMP have independent capital structures.

During the year ended December 31, 2013 and nine months ended September 30, 2014, less than $0.1 million and $0.1 million of distributions, respectively, were made in respect of the MEMP incentive distribution rights. Please see Business Relationship with Memorial Production Partners LP for further information on our interest in MEMP.

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Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile commodity prices and other material factors. For a discussion of these risks and other considerations that could negatively affect us, including risks related to this offering and our common stock, please read Risk Factors beginning on page 23 of this prospectus and Cautionary Note Regarding Forward-Looking Statements.

Corporate History and Structure

We are a Delaware corporation formed by MRD LLC in January 2014 engaged in the acquisition, exploitation, and development of natural gas, NGL and oil properties primarily in North Louisiana and East Texas. MRD LLC was a Delaware limited liability company formed on April 27, 2011 by the Funds to own, acquire, exploit and develop oil and natural gas properties.

We completed our initial public offering on June 18, 2014. In connection with the closing of our initial public offering, MRD LLC contributed to us substantially all of its assets, comprised of the following, in exchange for shares of our common stock (which were distributed to MRD LLC s sole member, MRD Holdco): (1) 100% of its ownership interests in Classic Hydrocarbons Holdings, L.P. (Classic), Classic Hydrocarbons GP Co., L.L.C. (Classic GP), Black Diamond Minerals, LLC (Black Diamond), Beta Operating Company, LLC (Beta Operating), MRD Operating LLC (MRD Operating) and MEMP GP, which owns a 0.1% general partner interest and 50% of the incentive distribution rights in MEMP, and (2) its 99.9% membership interest in WildHorse Resources. In addition, certain former management members of WildHorse Resources contributed to us the remaining 0.1% membership interest in WildHorse Resources, and also exchanged their incentive units in WildHorse Resources, for shares of our common stock and cash consideration. As a result, we are majority-owned by the group consisting of MRD Holdco and certain former management members of WildHorse Resources.

Following the completion of our initial public offering, MRD LLC distributed to MRD Holdco (i) its interests in BlueStone, MRD Royalty LLC, MRD Midstream, Golden Energy Partners LLC (Golden Energy) and Classic Pipeline; (ii) the MEMP subordinated units; (iii) the remaining cash released from its debt service reserve account in connection with the redemption of the PIK notes; and (iv) approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy s assets in May 2014. We also reimbursed MRD LLC for the approximately $17.2 million interest payment that it made on the PIK notes on June 15, 2014, which was distributed to MRD Holdco.

As part of the restructuring transactions, we merged Black Diamond into MRD Operating, and MRD LLC was merged into MRD Operating upon the termination of the PIK notes indenture on June 27, 2014.

For more information regarding BlueStone, see Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations MRD Segment. For more information about the services agreement with WildHorse Resources, see Certain Relationships and Related Party Transactions Services Agreement.

The following diagram shows our ownership structure after giving effect to this offering, assuming no exercise of the underwriters option to purchase additional shares from the selling stockholders, and does not give effect to 19,250,000 shares of common stock reserved for future issuance under the Memorial Resource Development Corp. 2014 Long Term Incentive Plan (described in Management 2014 Long Term Incentive Plan). See Principal and Selling Stockholders for the number of shares being offered by MRD Holdco and the other selling stockholders, respectively.

(1) If the underwriters exercise in full their option to purchase additional shares of common stock from the selling stockholders, the ownership interest of the public stockholders will increase to 84,779,211 shares of common stock, representing an aggregate 44% ownership interest in us, MRD Holdco will own 74,269,433 shares of common stock, representing an aggregate 38% ownership interest in us and certain former management members of WildHorse Resources will own 34,510,567 shares of common stock, representing an aggregate 18% ownership interest in us.
(2) As of October 31, 2014.
(3) The Funds refer collectively to Natural Gas Partners VIII, L.P., Natural Gas Partners IX, L.P. and NGP IX Offshore Holdings, L.P., which collectively control MRD Holdco. Please read Principal and Selling Stockholders for information regarding beneficial ownership. The Funds collectively indirectly own 50% of the Partnership s incentive distribution rights.
(4) Subsidiaries of MRD Holdco include BlueStone, MRD Royalty, MRD Midstream, Golden Energy and Classic Pipeline. Also, please see the Principal and Selling Stockholders table on page 148 for the beneficial ownership of our shares by our executive officers and directors.
(5) Includes Classic, Classic GP and Beta Operating.

Corporate Information

Our principal executive offices are located at 500 Dallas St., Suite 1800, Houston, Texas 77002, and our phone number is (713) 588-8300. Our website address is www.memorialrd.com. We make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, which we refer to as

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the SEC, available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this prospectus.

Emerging Growth Company Status

We are an emerging growth company as defined in the Jumpstart Our Business Startups Act (the JOBS Act). For as long as we are an emerging growth company, unlike other public companies that are not emerging growth companies, we are not required to:

- provide an auditor s attestation report on management s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002;
- provide more than two years of audited financial statements and related management s discussion and analysis of financial condition and results of operations;
- comply with any new requirements adopted by the Public Company Accounting Oversight Board, or the PCAOB, requiring mandatory audit firm rotation or a supplement to the auditor s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;
- provide certain disclosure regarding executive compensation required of larger public companies or hold shareholder advisory votes on executive compensation required by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act); or
- obtain shareholder approval of any golden parachute payments not previously approved.

We will cease to be an emerging growth company upon the earliest of:

- the last day of the fiscal year in which we have $1.0 billion or more in annual revenues;
- the date on which we become a large accelerated filer (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30);
- the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period; or
- the last day of the fiscal year following the fifth anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, or the Securities Act, for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

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The Offering

Selling Stockholders	MRD Holdco and certain former management members of WildHorse Resources.
Common stock offered by the selling stockholders	30,000,000 shares (or 34,500,000 shares, if the underwriters exercise in full their option to purchase additional shares).
Common stock to be outstanding immediately after the offering	193,559,211 shares. The number of shares of common stock outstanding will not change as a result of this offering.
Option to purchase additional shares	The selling stockholders have granted the underwriters a 30-day option to purchase up to an aggregate of 4,500,000 additional shares of our common stock held by the selling stockholders.
Common stock voting rights	Each share of our common stock entitles its holder to one vote.
Use of proceeds	We will not receive any of the proceeds from the sale of shares of our common stock by the selling stockholders, including pursuant to any exercise by the underwriters of their option to purchase additional shares of our common stock. The selling stockholders may be deemed under federal securities laws to be underwriters with respect to the common stock they may sell in connection with this offering.
Dividend policy	We currently intend to retain all future earnings, if any, for use in the operation of our business and to fund future growth. The decision whether to pay dividends in the future will be made by our board of directors (our Board) in light of conditions then existing, including factors such as our financial condition, earnings, available cash, business opportunities, legal requirements, restrictions in our debt agreements and other contracts and other factors our Board deems relevant. See Dividend Policy.
Risk factors	You should carefully read and consider the information set forth under Risk Factors beginning on page 23 of this prospectus and all other information set forth in this prospectus before deciding to invest in our common stock.
Listing and trading symbol	Our common stock is listed on the NASDAQ Global Select Market (NASDAQ) under the trading symbol MRD.

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Summary Historical Consolidated and Combined Pro Forma Financial Data

Prior to the restructuring transactions and the closing of our initial public offering, MRD LLC and its consolidated subsidiaries, our accounting predecessor, controlled MEMP through its ownership of MEMP GP, the general partner of MEMP. Because MRD LLC controlled MEMP through its ownership of the general partner, MRD LLC was required to consolidate MEMP for accounting and financial reporting purposes even though MRD LLC owned a minority of its partner interests and MRD LLC and MEMP had independent capital structures. MRD LLC received cash distributions from MEMP as a result of its partner interests and incentive distribution rights in MEMP, when declared and paid by MEMP. In connection with the closing of our initial public offering, MRD LLC contributed substantially all of its existing assets to us in exchange for shares of our common stock. Through our ownership of MEMP GP, we continue to control MEMP and therefore will continue to consolidate the results of MEMP into our consolidated financial statements in future periods.

Our predecessor had two reportable business segments, both of which were engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

MRD reflected all of MRD LLC s consolidating subsidiaries except for MEMP and its subsidiaries.

MEMP reflected the consolidated and combined operations of MEMP and its subsidiaries.

We continue to have two reportable segments. For more information regarding reportable business segments, please see the predecessor s audited historical financial statements and related notes and our unaudited historical interim financial statements included elsewhere in this prospectus.

The following tables include summary historical financial data for us and our predecessor, as well as the MRD Segment as of and for the periods indicated. The summary historical financial data of our predecessor as of and for the years ended December 31, 2013 and 2012 were derived from the audited historical financial statements of our predecessor included elsewhere in this prospectus. The summary historical financial data as of September 30, 2014 and for the nine months ended September 30, 2014 and 2013 were derived from our unaudited interim financial statements included elsewhere in this prospectus. The summary historical financial data of the MRD Segment as of and for the years ended December 31, 2013 and 2012 were derived from certain financial information used in the preparation of our predecessor s audited financial statements. The summary historical financial data for the MRD Segment as of September 30, 2014 and for the nine months ended September 30, 2014 and 2013 were derived from certain financial information used in the preparation of our unaudited interim financial statements.

The summary unaudited pro forma data for the nine months ended September 30, 2014 and for the year ended December 31, 2013 has been prepared to give pro forma effect to: (i) the exclusion of both BlueStone and Classic Pipeline as well as the MEMP subordinated units, none of which were conveyed to us in connection with our initial public offering; (ii) certain restructuring transactions that took place in connection with our initial public offering; (iii) the MEMP Wyoming Acquisition and the MEMP Offerings; (iv) our private placement on July 10, 2014 of $600.0 million aggregate principal amount of 5.875% senior unsecured notes at par as well as MEMP s private placement on July 17, 2014 of $500.0 million aggregate principal amount of 6.875% senior unsecured notes at 98.485% of par (collectively referred to as the Debt Offerings); and (v) incremental federal income tax expense.

We derived the data in the following tables from, and the following tables should be read together with and is qualified in its entirety by reference to, our historical financial statements (including those of our predecessor) and our pro forma financial statements and the accompanying notes included elsewhere in this prospectus. You should also read Management s Discussion and Analysis of Financial Condition and Results of Operations, and our pro forma and historical consolidated financial statements, all included elsewhere in this prospectus. Among

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other things, those historical consolidated and combined financial statements and pro forma financial statements include more detailed information regarding the basis of presentation for the following data.

	Year Ended December 31, 2013	Year Ended December 31, 2012	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Memorial Resource Development Corp. Pro Forma Year Ended December 31, 2013	Memorial Resource Development Corp. Pro Forma Nine Months Ended September 30, 2014
	(Predecessor)	(Predecessor)	(unaudited)	(Predecessor) (unaudited)	(unaudited)	(unaudited)
	(in thousands)					
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$ 571,948	$ 393,631	$ 669,301	$ 420,857	$ 740,221	$ 758,811
Other revenues	3,075	3,237	3,584	1,884	2,268	3,034
Total revenues	575,023	396,868	672,885	422,741	742,489	761,845
Costs and expenses:						
Lease operating	113,640	103,754	111,887	81,746	165,092	136,561
Pipeline operating	1,835	2,114	1,596	1,343	1,835	1,596
Exploration	2,356	9,800	1,465	2,265	2,356	1,465
Production and ad valorem taxes	27,146	23,624	33,623	23,478	53,079	45,515
Depreciation, depletion and amortization	184,717	138,672	215,906	132,328	233,244	244,357
Impairment of proved oil and gas properties	6,600	28,871	67,181	21	4,201	67,181
Incentive unit compensation expense			969,390	19,069		968,367
General and administrative	125,358	69,187	61,061	55,982	101,098	61,045
Accretion of asset retirement obligations	5,581	5,009	4,601	4,016	5,803	4,741
(Gain) loss on commodity derivatives	(29,294)	(34,905)	11,580	(29,556)	(29,311)	11,580
(Gain) loss on sale of property	(85,621)	(9,761)	3,057	(86,218)	3,927	3,167
Other, net	649	502	(12)	622	649	(12)
Total costs and expenses	352,967	336,867	1,481,335	205,096	541,973	1,545,563
Operating income (loss)	222,056	60,001	(808,450)	217,645	200,516	(783,718)
Other income (expense)						
Interest expense, net	(69,250)	(33,238)	(104,928)	(41,994)	(117,843)	(108,998)
Loss on extinguishment of debt			(37,248)			(37,248)
Amortization of investment premium		(194)				
Other, net	145	535	102	81	143	102
Total other income (expense)	(69,105)	(32,897)	(142,074)	(41,913)	(117,700)	(146,144)
Income tax benefit (expense)	(1,619)	(107)	(14,398)	(1,432)	(29,814)	(21,836)
Net income (loss)	$ 151,332	$ 26,997	$ (964,922)	$ 174,300	$ 53,002	$ (951,698)
Cash Flow Data:						
Net cash provided by operating activities	$ 277,823	$ 240,404	$ 365,460	$ 237,176		
Net cash used in investing activities	367,443	606,738	1,496,677	235,883		
Net cash provided by financing activities	117,950	361,761	1,063,812	32,261		
Balance Sheet Data (at period end):						
Working capital (deficit)	$ 48,256	$ 63,054	$ (71,531)			
Total assets	2,829,161	2,459,304	4,021,667			
Total debt	1,663,217	939,382	2,111,800			
Total equity (including noncontrolling interests)	858,132	1,276,709	1,458,999			

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	MRD Segment				MRD Segment Pro Forma	
	Year Ended December 31,		Nine Months Ended September 30,		Year Ended December 31,	Nine Months Ended September 30,
	2013	2012	2014	2013	2013	2014
			(unaudited)		(unaudited)	
			(in thousands)			
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$ 230,751	$ 138,032	$ 300,931	$ 171,013	$ 212,603	$ 299,242
Other revenues	807	782	561	348		11
Total revenues	231,558	138,814	301,492	171,361	212,603	299,253
Costs and expenses:						
Lease operating	25,006	24,438	18,657	17,065	23,354	18,723
Exploration	1,226	7,337	1,213	1,137	1,226	1,213
Production and ad valorem taxes	9,362	7,576	10,494	8,563	8,485	10,443
Depreciation, depletion and amortization	87,043	62,636	107,496	62,605	76,524	106,753
Impairment of proved oil and gas properties	2,527	18,339			128	
Incentive unit compensation expense			969,390	19,069		968,367
General and administrative	81,758	38,414	29,301	22,466	57,498	29,285
Accretion of asset retirement obligations	728	632	495	547	670	495
(Gain) loss on commodity derivatives	(3,013)	(13,488)	(17,130)	(8,361)	(3,030)	(17,130)
(Gain) loss on sale of property	(82,773)	(2)	3,057	(83,370)	6,775	3,167
Other, net	2	364		(25)	2	
Total costs and expenses	121,866	146,246	1,122,973	39,696	171,632	1,121,316
Operating income (loss)	109,692	(7,432)	(821,481)	131,665	40,971	(822,063)
Other income (expense)						
Interest expense, net	(27,349)	(12,802)	(44,355)	(15,947)	(45,972)	(32,151)
Loss on extinguishment of debt			(37,248)			(37,248)
Earnings from equity investments	1,066	4,880	(12,844)	(24)	269	18
Other, net	145	535	102	81	143	102
Total other income (expense)	(26,138)	(7,387)	(94,345)	(15,890)	(45,560)	(69,279)
Income tax (expense) benefit	(1,311)	178	(14,323)	(1,147)	1,652	(23,137)
Net income (loss)	$ 82,243	$ (14,641)	$ (930,149)	$ 114,628	$ (2,937)	$ (914,479)
Cash Flow Data (Unaudited):						
Net cash provided by operating activities	$ 83,910	$ 84,172	$ 181,683	$ 90,118		
Net cash used in investing activities	5,533	230,471	215,139	26,382		
Net cash provided by (used in) financing activities	(38,963)	133,271	(21,388)	(21,378)		
Other Financial Data:						
Adjusted EBITDA (unaudited)	$ 197,903	$ 132,105	$ 247,335	$ 153,679	$ 159,239	$ 258,982
Balance Sheet Data (at period end):						
Working capital (unaudited)	$ 51,214	$ 2,424	$ (17,799)			
Total assets	1,281,134	1,102,406	1,232,146			
Total debt	871,150	309,200	628,000			
Total equity (unaudited)	279,412	682,644	436,231			

Adjusted EBITDA

Our reportable business segments are organized in a manner that reflects how management manages those business activities.

We evaluate segment performance based on Adjusted EBITDA. The definition and calculation of Adjusted EBITDA and the reconciliation of total reportable segments Adjusted EBITDA to net income (loss) is included in the notes to our and our predecessor s consolidated and combined financial statements found elsewhere in this prospectus.

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Adjusted EBITDA (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in evaluating segment performance. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss). Our computation of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements. The following table provides a reconciliation of our pro forma MRD Segment net income to our pro forma MRD Segment Adjusted EBITDA.

Calculation of Adjusted EBITDA MRD Segment Pro Forma

	Year Ended December 31, 2013	Nine Months Ended September 30, 2014
Net income (loss)	$ (2,937)	$ (914,479)
Interest expense, net	45,972	32,151
Loss on extinguishment of debt		37,248
Income tax expense (benefit)	(1,652)	23,137
Depreciation, depletion and amortization	76,524	106,753
Impairment of proved oil and gas properties	128	
Accretion of AROs	670	495
(Gain) loss on commodity derivative instruments	(3,030)	(17,130)
Cash settlements received (paid) on commodity derivative instruments	12,257	(4,930)
(Gain) loss on sale of properties	6,775	3,167
Acquisition related costs	1,584	1,568
Incentive unit-based compensation expense	22,635	970,877
Exploration costs	1,226	1,213
Non-cash equity (income) loss from MEMP	(1,050)	12,844
Cash distributions from MEMP	137	6,068
Adjusted EBITDA	$ 159,239	$ 258,982

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Summary Reserve, Production and Operating Data for the MRD Segment

The following tables present summary data with respect to the estimated historical net proved oil and natural gas reserves and production and operating data for the MRD Segment as of the dates presented.

The proved reserve estimates presented in the table below were prepared by NSAI, and the probable and possible reserve estimates were prepared by our management and audited by NSAI. Regarding our properties, estimates comprising 100% of the total proved reserves in our reserve report were prepared by NSAI. These reserve estimates were prepared in accordance with current SEC rules regarding oil and natural gas reserve reporting. The following tables also contain certain summary information regarding production and sales of oil and natural gas with respect to such properties.

Please read Business Our Operations as well as Management s Discussion and Analysis of Financial Condition and Results of Operations and the summaries of our reserve report included herein as Appendices B-1 and B-2 in evaluating the material presented below.

Reserve Data

Estimated Proved Reserves	**As of December 31, 2013**
Natural gas (MMcf)	802,254
Oil/Condensate (MBbls)	11,311
NGLs (MBbls)	42,577
Total estimated net proved reserves (MMcfe)	1,125,577
Proved developed producing (MMcfe)	323,351
Proved developed non-producing (MMcfe)	44,290
Proved undeveloped (MMcfe)	757,936
Proved developed reserves as a percentage of total proved reserves	33%
PV-10 of proved reserves (in millions)(1)	$ 1,469
Estimated Probable Reserves(2)	
Natural Gas (MMcf)	535,185
Oil/Condensate (MBbls)	10,480
NGLs (MBbls)	33,709
Total estimated net probable reserves (MMcfe)	800,317
PV-10 of probable reserves (in millions)(1)	$ 1,052
Estimated Possible Reserves(2)	
Natural Gas (MMcf)	1,080,539
Oil/Condensate (MBbls)	36,376
NGLs (MBbls)	68,686
Total estimated net possible reserves (MMcfe)	1,710,913

PV-10 of possible reserves (in millions)(1)	$	2,386

(1) PV-10 is a non-GAAP financial measure and differs from standardized measure, the most directly comparable GAAP financial measure. Please see Reserves.
(2) Substantially all of our estimated probable and possible reserves are classified as undeveloped.

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Production and Operating Data

	Historical MRD Segment(1)				MRD Segment Pro Forma	
	Year Ended December 31,		Nine Months Ended September 30,		Year Ended December 31,	Nine Months Ended September 30,
	2013	2012	2014	2013	2013	2014
Production and operating data:						
Oil (MBbls)	665	369	689	498	523	677
NGLs (MBbls)	1,457	898	1,612	990	1,454	1,612
Natural gas (MMcf)	34,092	24,130	43,075	25,164	33,205	43,075
Total (MMcfe)	46,819	31,731	56,869	34,075	45,066	56,799
Average net production (MMcfe/d)	128.3	86.7	208.3	124.8	123.5	208.1
Average sales price:						
Oil (per Bbl)	$ 100.76	$ 95.56	$ 96.60	$ 101.77	$ 100.15	$ 96.61
NGLs (per Bbl)	36.99	40.78	41.93	37.69	36.93	41.93
Natural gas (per Mcf)	3.22	2.74	3.87	3.30	3.21	3.87
Average price per Mcfe	$ 4.93	$ 4.35	$ 5.29	$ 5.02	$ 4.73	$ 5.29
Average unit costs per Mcfe:						
Lease operating expenses	$ 0.53	$ 0.77	$ 0.33	$ 0.50	$ 0.52	$ 0.33
Production and ad valorem taxes	$ 0.20	$ 0.24	$ 0.18	$ 0.25	$ 0.19	$ 0.18
General and administrative(2)	$ 1.75	$ 1.21	$ 0.52	$ 0.66	$ 1.27	$ 0.52
Depletion, depreciation and amortization	$ 1.86	$ 1.97	$ 1.89	$ 1.84	$ 1.69	$ 1.88

(1) Includes production and operating data for BlueStone, Golden Energy and Classic Pipeline, which were not contributed to us in connection with our initial public offering. The MRD Segment Pro Forma production and operating data has been adjusted to exclude the production and operating data for BlueStone and Classic Pipeline.

(2) Includes $0.92 and $0.30 per Mcfe of incentive unit compensation expense for the historical MRD Segment for the years ended December 31, 2013 and 2012. The pro forma general and administrative expense for the year ended December 31, 2013 includes $0.50 per Mcfe of incentive unit compensation expense.

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RISK FACTORS

Investing in our common stock involves a high degree of risk. You should carefully consider the risks and uncertainties described below, as well as other information contained in this prospectus, before investing in our common stock. If any of the following risks actually occur, our business, financial condition, operating results or cash flow could be materially and adversely affected.

Risks Related to Our Business

Oil, natural gas and NGL prices are volatile, due to factors beyond our control, and will greatly affect our business, results of operations, liquidity and financial condition.

Our revenues, operating results, profitability, liquidity, future growth and the value of our properties depend primarily on prevailing commodity prices. Historically, oil and natural gas prices have been volatile and fluctuate in response to changes in supply and demand, market uncertainty, and other factors that are beyond our control, including:

- the regional, domestic and foreign supply of oil, natural gas and NGLs;
- the level of commodity prices and expectations about future commodity prices;
- the level of global oil and natural gas exploration and production;
- localized supply and demand fundamentals, including the proximity and capacity of pipelines and other transportation facilities, and other factors that result in differentials to benchmark prices from time to time;
- the cost of exploring for, developing, producing and transporting reserves;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;

- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- technological advances affecting exploration and production operations and overall energy consumption;
- domestic and foreign governmental regulations and taxes;
- the continued threat of terrorism and the impact of military and other action;
- the price and availability of competitors supplies of oil and natural gas and alternative fuels; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. For example, for the five years ended December 31, 2013, the NYMEX-WTI oil future price ranged from a high of $113.93 per Bbl to a low of $33.98 per Bbl, while the NYMEX-Henry Hub natural gas future price ranged from a high of $7.50 per MMBtu to a low of $1.82 per MMBtu. Any substantial decline in commodity prices will likely have a material adverse effect on our operations and financial condition, as well as on our level of expenditures for the development of our reserves.

NGLs comprised 23% of our estimated proved reserves at December 31, 2013 and accounted for 17% of our production on a volume equivalent basis for the nine months ended September 30, 2014. Realized NGL prices have decreased recently principally due to significant supply. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics. A further or extended decline in NGL prices could materially and adversely affect our future business, financial condition and results of operations.

The prices that we receive for our oil and natural gas production often reflect a regional discount, based on the location of production, to the relevant benchmark prices, such as NYMEX or ICE, that are used for calculating hedge positions. The prices we receive for our production are also affected by the specific characteristics of the production relative to production sold at benchmark prices. These discounts, if significant, could adversely affect our results of operations and financial condition.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.

As a recently formed company, growth in accordance with our business plan, if achieved, could place a significant strain on our financial, technical, operational and management resources. As we expand our activities and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical, operational and management resources. Pursuant to a services agreement entered into in connection with our initial public offering, we depend on the services of an entity managed by certain former management members of WildHorse Resources for supervising and managing our drilling operations in the Terryville Complex. See Certain Relationships and Related Party Transactions Services Agreement. Under certain circumstances, this agreement may be terminated by the parties thereto and we may be unable to find replacement services, which could materially and adversely affect our ability to execute our plans for the development of the Terryville Complex. In addition, the failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geologists, engineers and other professionals in the oil and natural gas industry, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

Unless we replace the oil and natural gas reserves we produce, our revenues and production will decline, which would adversely affect our business, results of operations, liquidity and financial condition.

Producing oil and natural gas reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production and therefore our cash flow and financial condition are highly dependent on our success in efficiently developing and exploiting our current reserves. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we drill additional wells or make acquisitions. We may not be able to develop, find or acquire additional reserves to replace our current and future production on economically acceptable terms, which would adversely affect our business, financial condition and results of operations.

If commodity prices decline, a significant portion of our development projects may become uneconomic and cause write downs of the value of our oil and natural gas properties, which may adversely affect our financial condition and liquidity.

Significantly lower oil prices, or sustained lower natural gas prices, would render many of our development and production projects uneconomic and result in a reduction of our estimated reserves, which would reduce the borrowing base under our revolving credit facility and our ability to finance planned or desired capital expenditures or acquisitions.

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Deteriorating commodity prices may cause us to recognize impairments in the value of our properties. In addition, if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our properties for impairments. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment or otherwise adversely affect our business, financial condition or results of operations.

Our drilling activities are subject to many risks. For example, we cannot assure you that wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry holes but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then-realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond our control, and increases in those costs can adversely affect the economics of a project. Further, our drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- loss of well control;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays or increases in the cost of equipment and services;
- reductions in oil, natural gas and NGL prices;
- lack of proximity to and shortage of capacity of transportation facilities;
- the limited availability of financing at acceptable rates;

- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements, which may include limitations on hydraulic fracturing or the discharge of greenhouse gases; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties.

Part of our strategy involves using horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;

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- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We own a significant amount of unproved property, which we expect to further our development efforts. We intend to continue to undertake acquisitions of unproved properties in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our results of operations over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. As of December 31, 2013, we had 10,825 gross (6,985 net) acres scheduled to expire in 2014, 20,078 gross (12,015 net) acres scheduled to expire in 2015, 31,215 gross (20,875 net) acres scheduled to expire in 2016 and 28,228 gross (19,649 net) acres scheduled to expire in 2017. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Moreover, many of our leases require lessor consent to pool, which may make it more difficult to hold our leases by production. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. In addition, in order to hold our current leases scheduled to expire in 2014 and 2015, we will need to operate at least a one-rig program. We cannot assure you that we will have the liquidity to deploy these rigs when needed, or that commodity prices will warrant operating such a drilling program. Any such losses of leases could materially and adversely affect the growth of our asset base, cash flows and results of operations.

We may incur losses as a result of title defects in the properties in which we invest.

The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

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Our project areas, which are in various stages of development, may not yield oil or natural gas in commercially viable quantities.

Our project areas are in various stages of development, ranging from project areas with current drilling or production activity to project areas that consist of recently acquired leasehold acreage or that have limited drilling or production history. At December 31, 2013, 10 gross (9.4 net) wells were in various stages of completion. If the wells in the process of being completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected. From January 2011 through December 31, 2013, we have drilled 83 gross (51.9 net) wells and, out of these wells, 3 gross (1.5 net) wells were dry holes.

Our identified drilling locations, which are scheduled out over many years, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

As of December 31, 2013, we had identified 1,582 gross (1,091 net) horizontal drilling locations on our existing acreage. Only 145 of these gross identified drilling locations had proved undeveloped reserves attributed to them in our reserve report. These drilling locations, including those with attributed proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory changes and approvals, negotiation of agreements with third parties, commodity prices, costs, the generation of additional seismic or geological information, the availability of drilling rigs, drilling results, construction of infrastructure, inclement weather, and lease expirations.

Further, our identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional analysis of data. We cannot predict in advance of drilling and testing whether any particular drilling location will yield production in sufficient quantities to recover drilling or completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas reserves exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in our areas of operations may not be indicative of future or long-term production rates.

A majority of our 1,431 gross horizontal drilling locations (as of December 31, 2013) within the Terryville Complex are identified within four distinct zones, with such gross horizontal drilling locations being roughly evenly distributed amongst such four zones. To date, we have drilled 41 horizontal wells within our four primary target zones in the Terryville Complex. Accordingly, we have limited experience in drilling horizontal wells in the zones of the Terryville Complex to which we have ascribed a substantial majority of our gross identified drilling locations. Please see Business Our Operations Drilling Locations for more information on our gross identified drilling locations.

Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas reserves from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operations.

We have identified drilling, recompletion and development locations and prospects for future drilling, recompletion and development. These drilling, recompletion and development locations represent a significant part of our future drilling and enhanced recovery opportunity plans. Our ability to drill, recomplete and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, the generation of additional seismic or geological information, the availability of drilling rigs, and drilling results. Because of these uncertainties, we cannot be certain of the timing of these activities or that they will ultimately result in the realization of estimated proved reserves or meet our expectations for success. As such, our actual drilling and enhanced recovery activities may materially differ from our current expectations, which could have a significant adverse effect on our estimated reserves, financial condition and results of operations.

The development of our proved undeveloped and unproved reserves may take longer and may require higher levels of capital expenditures than we anticipate and may not be economically viable.

Approximately 67% of our total proved reserves at December 31, 2013 were proved undeveloped reserves; those reserves may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Moreover, the development of probable and possible reserves will require additional capital expenditures and such reserves are less certain to be recovered than proved reserves. The reserve data included in our reserve report assumes that substantial capital expenditures are required to develop such undeveloped reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as proved undeveloped reserves.

Our acquisition and development operations require substantial capital expenditures.

The development and production of our oil and natural gas reserves requires substantial capital expenditures. If our revenues decrease, as a result of lower oil or natural gas prices or for any other reason, we may not be able to obtain the capital necessary to sustain our operations at our current level. In addition, our ability to acquire additional properties will be adversely affected if we are unable to fund such acquisitions from cash flow from operations or other sources.

Shortages of rigs, equipment and crews could delay our operations, increase our costs and delay forecasted revenue.

Higher oil and natural gas prices generally increase the demand for rigs, equipment and crews and can lead to shortages of, and increasing costs for, development equipment, services and personnel. Shortages of, or increasing costs for, experienced development crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues and thus the results of our operations.

Our hedging strategy may not effectively mitigate the impact of commodity price volatility from our cash flows, and our hedging activities could result in cash losses and may limit potential gains.

We intend to maintain a portfolio of commodity derivative contracts. These commodity derivative contracts include natural gas, oil and NGL financial swaps and collar contracts and natural gas basis financial swaps. The prices and quantities at which we enter into commodity derivative contracts covering our production in the future will be dependent upon oil and natural gas prices and price expectations at the time we enter into these transactions, which may be substantially higher or lower than current or future oil and natural gas prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil and natural gas prices received for our future production. In addition, our revolving credit facility limits our ability to enter into commodity hedges covering greater than 85% of our reasonably anticipated projected production.

Many of the derivative contracts to which we will be a party will require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil and natural gas prices. If our actual production and sales for any period are less than our hedged production and sales for that period (including reductions in production due to operational delays) or if we are unable to perform our drilling activities as planned, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, which may materially impact our liquidity.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets or other unforeseen events could lead to sudden changes in a counterparty s liquidity, which could impair its ability to perform under the terms of the derivative contract and, accordingly, prevent us from realizing the benefit of the derivative contract.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary.

The process also requires economic assumptions about matters such as natural gas prices, oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil prices, natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust our reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from our reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

SEC rules could limit our ability to book additional PUDs in the future.

SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional PUDs as we pursue our drilling program. Moreover, we may be required to write down our PUDs if we do not drill those wells within the required five-year timeframe.

The PV-10 of our estimated proved, probable and possible reserves is not necessarily the same as the current market value of our estimated proved oil and natural gas reserves.

The present value of future net cash flows from our proved, probable and possible reserves shown in this prospectus, or PV-10, may not be the current market value of our estimated natural gas and oil reserves. In accordance with rules established by the SEC and the Financial Accounting Standards Board (FASB), we base the

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estimated discounted future net cash flows from our proved reserves on the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Our producing properties are concentrated in North Louisiana and East Texas, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in North Louisiana and East Texas. At December 31, 2013, 99% of our total estimated proved reserves and for the nine months ended September 30, 2014, 97% of our net average daily production was attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

Expenses not covered by our insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including natural disasters, the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. In addition, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The location of any properties and other assets near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of operations, substantial revenue losses and repairs to resume operations.

We maintain insurance coverage against potential losses that we believe is customary in the industry. However, these policies may not cover all liabilities, claims, fines, penalties or costs and expenses that we may incur in connection with our business and operations, including those related to environmental claims. Pollution and environmental risks generally are not fully insurable. In addition, we cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, revenues, capital expenditures, operating expenses and costs;

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- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate;

- an inability to obtain satisfactory title to the assets we acquire; and

- potential lack of operating experience in the geographic market where the acquired assets or business are located.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

NGP, the Funds and their affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses.

Our governing documents provide that NGP and the Funds and their respective affiliates (including NGP and its affiliates portfolio investments) are not restricted from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, NGP and the Funds and their respective affiliates may acquire, develop or dispose of additional oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets.

NGP and the Funds are established participants in the oil and natural gas industry, and have resources greater than ours, which factors may make it more difficult for us to compete with them with respect to commercial activities as well as for potential acquisitions. As a result, competition from these affiliates could adversely impact our results of operations.

We may be unable to compete effectively with larger companies.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas, and securing equipment and trained personnel. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis, and many of our competitors have access to capital at a lower cost than that available to us. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Furthermore, we may not be able to aggregate sufficient quantities of production to compete with larger companies that are able to sell greater volumes of production to intermediaries, thereby reducing the realized prices attributable to our production. Any inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

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We require substantial capital expenditures to conduct our operations, engage in acquisition activities and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy.

We require substantial capital expenditures to conduct our exploration, development and production operations, engage in acquisition activities and replace our production. We have established a capital budget for 2014 of approximately $351 million and we intend to rely on cash flow from operating activities as our primary sources of liquidity. We also may engage in asset and equity sale transactions to, among other things, fund capital expenditures when market conditions permit us to complete transactions on terms we find acceptable. There can be no assurance that such sources will be sufficient to fund our exploration, development and acquisition activities. If our revenues and cash flows decrease in the future as a result of a decline in commodity prices or a reduction in production levels, however, and we are unable to obtain additional equity or debt financing in the capital markets or access alternative sources of funds, we may be required to reduce the level of our capital expenditures and may lack the capital necessary to replace our reserves or maintain our production levels.

Our business depends in part on pipelines, gathering systems and processing facilities owned by us or others. Any limitation in the availability of those facilities could interfere with our ability to market our oil and natural gas production.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipelines and other transportation methods, gathering systems and processing facilities owned by third parties. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of contracted capacity on such systems. Our access to transportation options can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided with only limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation or processing facility capacity could reduce our ability to market our oil and natural gas production and harm our business.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our natural gas and oil exploration, production, and transportation operations are subject to complex and stringent laws and regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment and thus, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition, and results of operations.

Our oil and natural gas development and production operations are also subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of a permit before conducting regulated drilling activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency, or the EPA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue.

Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons, or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

Please read Business Regulation of Environmental and Occupational Health and Safety Matters for a further description of the laws and regulations that affect us.

Climate change legislation or regulations restricting emissions of greenhouse gases, or GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases (GHGs), including carbon dioxide and methane, may be contributing to warming of the earth s atmosphere and other climatic changes. In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth s atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the federal Clean Air Act (CAA) that establish Prevention of Significant Deterioration, or PSD, and Title V permit reviews for GHG emissions

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from certain large stationary sources. On June 23, 2014, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD or Title V programs. The EPA has announced that it is currently evaluating the decision and awaiting further action by the courts, and that it will provide relevant guidance on GHG permitting requirements.

The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources on an annual basis in the United States, including, among others, certain oil and natural gas production facilities, which includes certain of our operations. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. In addition, the Obama administration has announced in its Climate Action Plan that it intends to adopt additional regulations to reduce emissions of GHGs in the coming years, possibly including further restrictions on emissions of methane from oil and gas operations.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Please read Business Regulation of Environmental and Occupational Health and Safety Matters for a further description of the laws and regulations that affect us.

The listing of a species as either threatened or endangered under the federal Endangered Species Act could result in increased costs and new operating restrictions, loss of leasehold or delays on our operations, which could adversely affect our results of operations and financial condition.

The federal Endangered Species Act (ESA) and analogous state laws restrict activities that may adversely affect endangered and threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The designation of previously unidentified endangered or threatened species in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans. Numerous species have been listed or proposed for protected status in areas in which we currently, or could in the future, undertake operations. For instance, the American burying beetle and the lesser prairie chicken both have habitat in some areas where we operate. The U.S. Fish and Wildlife Service (FWS) identified the lesser prairie chicken, which inhabits portions of Colorado, Kansas, Nebraska, New Mexico, Oklahoma and Texas, as candidate for listing in 1998 and has listed it as threatened in March 2014. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies, pursuant to

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which such parties agreed to take steps to protect the lesser prairie chicken s habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken s habitat. The threatened species status of the lesser prairie chicken is currently subject to a pending lawsuit by at least three states. The lawsuit challenges FWS recent classification of the lesser prairie chicken. The presence of protected species in areas where we operate could impair our ability to timely complete or carry out those operations, lose leaseholds as we may not be permitted to timely commence drilling operations, cause us to incur increased costs arising from species protection measures, and, consequently, adversely affect our results of operations and financial position.

The third parties on whom we rely for gathering and transportation services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations. See Business Regulation of Environmental and Occupational Health and Safety Matters and Business Regulation of the Oil and Natural Gas Industry for a description of the laws and regulations that affect the third parties on whom we rely.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission, or CFTC, adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities. Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC has issued a large number of rules to implement the Dodd-Frank Act, including a rule establishing an end-user exception to mandatory clearing, referred to herein as the End-User Exception, and a rule imposing position limits, referred to herein as the Initial Position Limit Rule. The Initial Position Limit Rule was vacated and remanded to the CFTC for further proceedings by order of the United States District Court for the District of Columbia on September 28, 2012. The CFTC proposed a new version of the Initial Position Limit Rule in November 2013, referred to herein as the Re-Proposed Position Limit Rule, with respect to which the comment period has closed but a final rule has not been issued. The CFTC and bank regulators in September 2014 re-proposed rules which would impose margin requirements on uncleared swaps between banks, swap dealers and major swap participants, referred to herein as the Re-Proposed SD/MSP Margin Rule.

We qualify as a non-financial entity for purposes of the End-User Exception and we utilize such exception so our hedging activity is not subject to mandatory clearing or the margin requirements imposed in connection with mandatory clearing. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End-User Exception and, if the Re-Proposed SD/MSP Margin Rule is adopted, will be subject to such rule and required to post margin in accordance with such rule in connection with their swaps with other banks, swap dealers and major swap participants. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Re-Proposed Position Limit Rule and the Re-Proposed SD/MSP Margin Rule are ultimately effected, such proposed rules could significantly increase the cost of derivative contracts (including through requirements to post collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect

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against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. We routinely apply hydraulic fracturing techniques in our drilling and completion programs.

While hydraulic fracturing has historically been regulated by state oil and natural gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. For example, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the Safe Drinking Water Act, or the SDWA, involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Although the EPA is not the permitting authority for the SDWA s Underground Injection Control Class II programs in Louisiana, Texas, Wyoming, New Mexico, or Colorado, where we or MEMP maintain operational acreage, the EPA is encouraging state programs to review and consider use of such draft guidance. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in late 2014. In addition, in October 2011, the EPA announced its plan to propose federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting flowback, as well as produced water. If adopted, the new pretreatment rules will require shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected sometime in 2014. Moreover, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014.

In August 2012, the EPA adopted rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants programs. The rules include NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or green completions on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules could require a number of modifications to our operations including the installation of new equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that are likely to be responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rules addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On July 1, 2014, the EPA announced proposed amendments and clarifications to the NSPS standards. These standards, as well as any future laws and their implementing regulations, may require us to

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obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, in May 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed rule would continue to require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. The Bureau of Land Management plans to issue a final rule in 2014.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft report is expected to be released for public comment and review in late 2014. The EPA s study could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing.

Additionally, Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Certain states, including Texas and Colorado, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, in October 2011, the Louisiana Department of Natural Resources adopted new rules requiring the public disclosure of the composition and volume of fracturing fluids used in hydraulic fracturing operations. Also, October 28, 2014, the Texas Railroad Commission adopted disposal well rule amendments designed, amongst other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments also clarify the Commission s authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The disposal well rule amendments become effective November 17, 2014. Furthermore, in May 2013, the Texas Railroad Commission adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted at the state and local level, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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Oil and natural gas producers operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. Restrictions on the ability to obtain water may impact our operations.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations. Moreover, the imposition of new environmental requirements could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The Federal Water Pollution Control Act (the CWA) imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. State and federal discharge regulations prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Also, the EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

We are not the only partners in MEMP, and MEMP s partnership agreement requires it to distribute all available cash to its partners, including public unitholders.

MEMP is a publicly traded limited partnership. We own MEMP GP, the sole general partner of MEMP, and are entitled to 50% of any cash distributed in respect of MEMP s incentive distribution rights. MRD Holdco owns 5,360,912 subordinated units representing an approximate 6.2% limited partner interest in MEMP. The remainder of the outstanding limited partner interests in MEMP are common units owned by public unitholders. MEMP s partnership agreement requires it to distribute, on a quarterly basis, 100% of its available cash to its partners. We receive only our proportionate share of cash distributions from MEMP based on our partner interests in it. The remainder of the quarterly cash distributions is distributed, pro rata, to the public unitholders (and, in the case of 50% of the incentive distribution rights, to the Funds).

For MEMP, available cash is generally all cash on hand at the end of each quarter, after payment of fees and expenses and the establishment of cash reserves by its general partner. MEMP GP determines the amount and timing of cash distributions by MEMP and has broad discretion to establish and make additions to MEMP s reserves in amounts the general partner determines to be necessary or appropriate:

- to provide for the proper conduct of partnership business, which could include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;
- to comply with applicable law, any of MEMP s debt instruments or other agreements; and
- to provide funds for distributions to the unitholders and the general partner for any one or more of the next four calendar quarters.

Accordingly, cash distributions we receive on our MEMP partner interests may be reduced at any time, or we may not receive any cash distributions from MEMP.

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The amount of cash that MEMP will be able to distribute to us principally depends upon the amount of cash it can generate from its oil and natural gas production business.

A significant decline in MEMP s earnings or cash distributions would have a negative impact on its distributions to its partners, including us. The amount of cash that MEMP will be able to distribute to its partners, including us, each quarter principally depends upon the amount of cash it can generate from its oil and natural gas production business. That amount of cash will fluctuate from quarter to quarter based on, among other things:

- the amount of oil, natural gas and NGLs MEMP produces;
- the prices at which MEMP sells its oil, natural gas and NGL production;
- the amount and timing of settlements of its commodity derivatives;
- the level of MEMP s operating costs, including maintenance capital expenditures and payments to MEMP GP and its affiliates; and
- the level of MEMP s interest expense, which depends on the amount of its indebtedness and the interest payable thereon.

Because of these factors, MEMP may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. In addition, our 50% incentive distribution rights are only entitled to distributions from MEMP in any quarter if MEMP has paid at least $0.54625 on each outstanding common unit and subordinated unit for such quarter. If MEMP reduces its per unit distribution below such amounts, we will receive less cash.

Conflicts of interest may arise because the board of directors of MEMP GP has a fiduciary duty to manage the general partner in a manner that is beneficial to the owner of MEMP GP, and at the same time, to manage MEMP in a manner that is beneficial to the MEMP unitholders. Conflicts may also arise because our executive officers have significant equity interests in MEMP.

We own MEMP GP, the sole general partner of MEMP. MEMP is a publicly traded limited partnership. The board of directors of MEMP GP owes specified duties to the MEMP unitholders, and also owes specified duties to us as owner of MEMP GP. As a result of these conflicts, the board of directors of MEMP GP may favor the interests of the MEMP public unitholders over our interests.

Our executive officers have significant equity interests in MEMP. As of September 30, 2014, Mr. Weinzierl, our Chief Executive Officer, owns 485,093 MEMP common units; Mr. Scarff, our President, owns 90,943 MEMP common units; Mr. Cozby, our Senior Vice President and Chief Financial Officer, owns 152,471 MEMP common units; Mr. Forney, our Senior Vice President and Chief Operating Officer, owns 143,081 MEMP common units; Mr. Roane, our Senior Vice President, General Counsel and Corporate Secretary, owns 83,818 MEMP common units; and Mr. Robbins, our Senior Vice President, Corporate Development, owns 89,782 MEMP common units. As a result of our executive officers significant holdings of MEMP common units, our executive officers may favor the interests of MEMP over our interests.

If MEMP s unitholders remove MEMP GP, we would lose our general partner interest and incentive distribution rights in MEMP and the ability to manage MEMP.

We currently manage our investment in MEMP through our ownership interest in MEMP GP. MEMP s partnership agreement, however, gives unitholders of MEMP the right to remove its general partner upon the affirmative vote of holders of 66 2/3% of the MEMP s outstanding units. If MEMP GP were removed as general partner of MEMP, it would receive cash or common units in exchange for its 0.1% general partner interest and incentive distribution rights and would also lose its ability to manage MEMP. While the cash or common units the general partner would receive are intended under the terms of MEMP s partnership agreement to fully compensate MEMP GP in the event such an exchange is required, the value of the investments we make with the cash or the common units may not over time be equivalent to the value of the general partner interest and the incentive distribution rights had MEMP GP retained them.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

We have a substantial amount of indebtedness. As of September 30, 2014, we had aggregate indebtedness of approximately $628 million at the MRD Segment. The terms and conditions governing our indebtedness:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increase our vulnerability to economic downturns and adverse developments in our business;
- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- limit management s discretion in operating our business.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we do not have enough money, we may be required to refinance all or part of our existing debt, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all. For example, our existing and future debt agreements will require that we satisfy certain conditions, including coverage and leverage ratios, to borrow money. Our existing and future debt agreements will also restrict the payment of dividends and distributions by certain of our subsidiaries to us, which could affect our access to cash. In addition, our ability to comply with the financial and other restrictive covenants in our indebtedness will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. Failure to comply with these covenants would result in an event of default under our indebtedness, and such an event of default could adversely affect our business, financial condition and results of operations.

We may not be able to generate enough cash flow to meet our debt obligations and may be forced to take other actions to satisfy our debt obligations which may not be successful.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can service in some periods may not be appropriate for us in other periods. Moreover, and subject to certain limitations, we and our subsidiaries may be able to incur substantial additional indebtedness in the future. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and from our subsidiaries and to pay our debt. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

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If we do not generate enough cash flow from operations and from our subsidiaries to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing, could materially and adversely affect our ability to make payments on our indebtedness and our business, financial condition and results of operations.

Furthermore, our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including our revolving credit facility, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our existing debt instruments currently restrict, and we expect our revolving credit facility will restrict, our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

Risks Relating to this Offering and Our Common Stock

The underwriters of this offering may waive or release parties to the lock-up agreements entered into in connection with this offering, which could adversely affect the price of our common stock.

The Company, the selling stockholders, our directors and officers and WHR Incentive LLC, a limited liability company beneficially owned by Messrs. Anthony Bahr and Jay Graham, have entered into lock-up agreements with respect to their common stock, pursuant to which they are subject to certain resale restrictions for a period of 60 days following the date of this prospectus. Citigroup Global Markets Inc., at any time, may release all or any portion of the common stock subject to the foregoing lock-up agreements. If the restrictions under the lock-up agreements are waived, then common stock will be available for sale into the public markets, which could cause the market price of our common stock to decline and impair our ability to raise capital.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock is influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

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NGP has the ability to direct the voting of more than a majority of our common stock, and its interests may conflict with those of our other stockholders.

NGP, through the Funds, beneficially owns all of the voting interests in MRD Holdco. Upon completion of this offering, MRD Holdco will own in the aggregate approximately 40% of the combined voting power of our common stock (or approximately 38% if the underwriters option to purchase additional shares of common stock from the selling stockholders is exercised in full). MRD Holdco and certain former management members of WildHorse Resources (which former management members, upon completion of this offering, will own in the aggregate approximately 18% of the combined voting power of our common stock (or approximately 18% if the underwriters option to purchase additional shares of common stock from the selling stockholders is exercised in full)) are party to a voting agreement, pursuant to which the former management members of WildHorse Resources agree, among other things, to vote all of their shares as directed by MRD Holdco. As a result, MRD Holdco and, thus, NGP are able to control matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. The interests of NGP with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders. Given this concentrated ownership, NGP would have to approve any potential acquisition of us. In addition, certain of our directors are currently employees of NGP. These directors duties as employees of NGP may conflict with their duties as our directors, and the resolution of these conflicts may not always be in our or your best interest.

Many of the directors and all of the officers who have responsibility for our management have significant duties with, and spend significant time serving, entities that may compete with us in seeking acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

Most of our officers hold similar positions with MRD Holdco and MEMP GP, and many of our directors, who are responsible for managing the direction of our operations and acquisition activities, hold positions of responsibility with other entities (including NGP-affiliated entities) that are in the business of identifying and acquiring oil and natural gas properties. For example, the Funds and their affiliates (including NGP) are in the business of investing in oil and natural gas companies with independent management teams that also seek to acquire oil and natural gas properties, and MRD Holdco and MEMP are both in the business of acquiring and developing oil and natural gas properties. Mr. Hersh, one of our directors, is a managing partner of NGP; Mr. Gieselman, one of our directors, is a managing director of NGP; Mr. Weber, one of our directors, is a managing partner of NGP and serves as Chief Operating Officer for NGP; Mr. Innamorati, one of our directors, is a director of MEMP GP, and Mr. Weinzierl, our Chief Executive Officer and one of our directors, is the Chief Executive Officer and Chairman of MEMP GP, and was a managing director and operating partner of NGP and continues to hold ownership interests in the Funds and certain of their affiliates. Our officers will continue to devote significant time to the business of MEMP and MRD Holdco and face conflicts in allocating their time on our behalf and on behalf of MEMP GP and MRD Holdco. Our officers have also historically received a significant portion of their overall compensation in MEMP unit awards under the long term incentive plan of MEMP GP. We cannot assure you that any conflicts that may arise between us and our stockholders, on the one hand, and MRD Holdco, MEMP, or the Funds, on the other hand, will be resolved in our favor. The existing positions held by these directors and officers may give rise to fiduciary or other duties that are in conflict with the duties they owe to us. These officers and directors may become aware of business opportunities that may be appropriate for presentation to us as well as to the other entities with which they are or may become affiliated. Due to these existing and potential future affiliations, they may present potential business opportunities to other entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that certain opportunities are more appropriate for other entities with which they are affiliated, and as a result, they may elect not to present those opportunities to us. These conflicts may not be resolved in our favor. For additional discussion of our management s business affiliations and the potential conflicts of interest of which our stockholders should be aware, see Certain Relationships and Related Party Transactions.

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The corporate opportunity provisions in our amended and restated certificate of incorporation could enable NGP, MRD Holdco or the Funds to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our amended and restated certificate of incorporation, among other things:

- permits any of NGP, MRD Holdco, the Funds, their respective affiliates, or our officers or directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and

- provides that if NGP, MRD Holdco, the Funds or their respective affiliates or any director or officer of one of our affiliates, NGP, MRD Holdco, the Funds or their respective affiliates who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter, they will have no duty to communicate or offer that opportunity to us.

As a result, NGP, MRD Holdco, the Funds or their affiliates may become aware, from time to time, of certain business opportunities (such as acquisition opportunities) and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to NGP, MRD Holdco or the Funds and their affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours. Please read Description of Capital Stock.

We are a controlled company within the meaning of the NASDAQ rules and, as a result, qualify for, and rely on, exemptions from certain corporate governance requirements.

MRD Holdco and certain former management members of WildHorse Resources, as a group, control a majority of our voting common stock. As a result, we are a controlled company within the meaning of applicable corporate governance standards. Under the NASDAQ rules, a company of which more than 50% of the voting power is held by an individual, group or another company is a controlled company and may elect not to comply with certain corporate governance requirements, including:

- the requirement that we have a majority of independent directors on our Board;

- the requirement that we have a nominating committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities;

- the requirement that we have a compensation committee that is composed entirely of independent directors; and

- the requirement for an annual performance evaluation of the nominating and compensation committees.

We utilize the foregoing exemptions from the applicable corporate governance requirements. As a result, we do not have a majority of independent directors and do not have a compensation committee. See Management. Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the applicable corporate governance requirements.

The price of our common stock may fluctuate significantly and you could lose all or part of your investment.

Volatility in the market price of our common stock may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

our operating and financial performance and prospects;

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- changes in earnings estimates or recommendations by securities analysts who track our common stock or industry;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy; and
- sales of common stock by us, our stockholders (including the Funds), or members of our management team.

In addition, the stock market has experienced significant price and volume fluctuations in recent years. This volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industries. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with us, and these fluctuations could materially reduce our share price.

We currently have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

We currently have no plans to pay regular dividends on our common stock. Any payment of dividends in the future will be at the discretion of our Board and will depend on, among other things, our earnings, financial condition and business opportunities, the restrictions in our debt agreements, and other considerations that our Board deems relevant. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

We may sell additional shares of common stock in subsequent public offerings or otherwise, including to finance acquisitions. Our amended and restated certificate of incorporation authorizes us to issue 600,000,000 shares of common stock, of which 193,559,211 shares are outstanding. The outstanding share number includes 49,220,000 shares registered and sold in our initial public offering and up to 34,500,000 shares that the selling stockholders are selling in this offering (assuming the underwriters exercise their option to acquire additional shares in full), all of which may be resold immediately in the public market. Following the expiration of the applicable lock-up period, which is 60 days after the date of this prospectus, 111,928,871 shares of our common stock may be sold into the public market (assuming the underwriters do not exercise their option to acquire additional shares), subject to compliance with the Securities Act or exemptions therefrom. See Shares Eligible for Future Sale for a discussion of the shares of our common stock that may be sold into the public market in the future.

MRD Holdco and certain former management members of WildHorse Resources are party to the Registration Rights Agreement, which requires us to effect the registration of their shares in certain circumstances. Upon the effectiveness of such a registration statement, all shares covered by the registration statement would be freely transferable without restriction or further registration under the Securities Act, except for any such shares which are acquired by any of our affiliates as that term is defined in Rule 144 under the Securities Act, which will be subject to the resale limitations of Rule 144. See Certain Relationships and Related Party Transactions Registration Rights Agreement.

We filed a registration statement with the SEC on Form S-8 providing for the registration of 19,250,000 shares of our common stock issued or reserved for issuance under our Memorial Resource Development Corp. 2014 Long Term Incentive Plan. Subject to the satisfaction of vesting conditions and the expiration of lock-up agreements, shares registered under our registration statement on Form S-8 are available for resale immediately in the public market without restriction.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial

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amounts of our common stock (including any shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our organizational documents and the voting agreement may impede or discourage a takeover, which could deprive our investors of the opportunity to receive a premium for their shares.

Provisions of our amended and restated certificate of incorporation, our amended and restated bylaws and the voting agreement may make it more difficult for, or prevent a third party from, acquiring control of us. These provisions include:

- requiring that certain former management members of WildHorse Resources vote all of their shares of our common stock, including with respect to the election of our directors, as directed by MRD Holdco;
- at such time MRD Holdco, NGP or as the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, our Board will be divided into three classes with each class serving staggered three year terms;
- at such time MRD Holdco, NGP or as the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, any action by stockholders may only be taken at an annual meeting or special meeting and may no longer be effected by a written consent of the stockholders, subject to the rights of any series of preferred stock with respect to such rights;
- at such time as MRD Holdco, NGP or the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, special meetings of our stockholders may only be called by our Board pursuant to a resolution adopted by the affirmative vote of a majority of the total number of authorized directors whether or not there exist any vacancies in previously authorized directorships (prior to such time, a special meeting may also be called at the request of stockholders holding a majority of the outstanding shares entitled to vote);
- at such time as MRD Holdco, NGP or the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, the affirmative vote of the holders of at least 75% in voting power of all then outstanding common stock entitled to vote generally in the election of directors, voting together as a single class, shall be required to remove any or all of the directors from office at any time;
- prohibiting cumulative voting in the election of directors; and
- authorizing the issuance of blank check preferred stock without any need for action by stockholders.

Our issuance of shares of preferred stock could delay or prevent a change in control of us. Our Board has authority to issue shares of preferred stock without stockholder approval in one or more series, designate the number of shares constituting any series, and fix the rights, preferences, privileges and restrictions thereof, including dividend rights, voting rights, rights and terms of redemption, redemption price or prices and liquidation preferences of such series. The issuance of shares of our preferred stock may have the effect of delaying, deferring or preventing a change in control without further action by the stockholders, even where stockholders are offered a premium for their shares.

Together, our amended and restated certificate of incorporation, amended and restated bylaws and the voting agreement could make the removal of management more difficult and may discourage transactions that otherwise could involve payment of a premium over prevailing market prices for our common stock. Furthermore, the existence of the foregoing provisions, as well as the significant amount of common stock beneficially owned by the Funds, could limit the price that investors might be willing to pay in the future for shares of our common stock. They could also deter potential acquirers of us, thereby reducing the likelihood that you could receive a premium for your common stock in an acquisition. See Description of Capital Stock Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, our Amended and Restated Bylaws and Delaware Law.

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We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies, as described under the caption Certain Relationships and Related Party Transactions. The resolution of any conflicts that may arise in connection with any related party transactions that we have entered into with MEMP, NGP, MRD Holdco, the Funds or their affiliates, including pricing, duration or other terms of service, may not always be in our or our stockholders best interests because NGP or the Funds may have the ability to influence the outcome of these conflicts. For a discussion of potential conflicts, please read NGP has the ability to direct the voting of more than a majority of our common stock, and its interests may conflict with those of our other stockholders.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our amended and restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our Board may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock. See Description of Capital Stock Limitation of Liability and Indemnification Matters.

The additional requirements of having a class of publicly traded equity securities may strain our resources and distract management.

As a public company, we are subject to additional reporting requirements of the Securities and Exchange Act of 1934 (the Exchange Act), the Sarbanes-Oxley Act of 2002 and the Dodd-Frank Act. The Dodd-Frank Act effects comprehensive changes to public company governance and disclosures in the United States and subject to additional federal regulation. We cannot predict with any certainty the requirements of the regulations ultimately adopted or how the Dodd-Frank Act and such regulations will impact the cost of compliance for a company with publicly traded common stock. We are currently evaluating and monitoring developments with respect to the Dodd-Frank Act and other new and proposed rules and cannot predict or estimate the amount of the additional costs we may incur or the timing of such costs. These laws, regulations and standards are subject to varying interpretations, in many cases due to their lack of specificity, and, as a result, their application in practice may evolve over time as new guidance is provided by regulatory and governing bodies. This could result in continuing uncertainty regarding compliance matters and higher costs necessitated by ongoing revisions to disclosure and governance practices. We intend to invest resources to comply with evolving laws, regulations and standards, and this investment may result in increased general and administrative expenses and a diversion of management s time and attention from revenue-generating activities to compliance activities. If our efforts to comply with new laws, regulations and standards differ from the activities intended by regulatory or governing bodies due to ambiguities related to practice, regulatory authorities may initiate legal proceedings against us and our business may be harmed. We also expect that being a company with publicly traded common stock and these new rules and regulations will make it more expensive for us to obtain director and officer liability insurance, and we may be required to accept reduced coverage or incur substantially higher costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our Board, particularly to serve on our audit committee, and qualified executive officers.

The Sarbanes-Oxley Act requires that we maintain effective disclosure controls and procedures and internal control over financial reporting. These requirements may place a strain on our systems and resources. Under

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Section 404 of the Sarbanes-Oxley Act, we will be required to include a report of management on our internal control over financial reporting in our Annual Reports on Form 10-K beginning with the Form 10-K for the year ending December 31, 2014. In order to maintain and improve the effectiveness of our disclosure controls and procedures and internal control over financial reporting, significant resources and management oversight are required. This may divert management s attention from other business concerns, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. If we are unable to conclude that our disclosure controls and procedures and internal control over financial reporting are effective, or if we are no longer an emerging growth company and our independent public accounting firm is unable to provide us with an unqualified report on our internal control over financial reporting in future years, investors may lose confidence in our financial reports and our stock price may decline.

We may remain an emerging growth company for up to five years. After we are no longer an emerging growth company, we expect to incur significant additional expenses and devote substantial management effort toward ensuring compliance with those requirements applicable to companies that are not emerging growth companies, including Section 404 of the Sarbanes-Oxley Act.

We are an emerging growth company and we cannot be certain if the reduced disclosure requirements applicable to emerging growth companies will make our common stock less attractive to investors.

We are an emerging growth company, as defined in the JOBS Act, and we currently take advantage of certain exemptions from various reporting requirements that are applicable to other public companies, including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved. We intend to take advantage of these reporting exemptions until we are no longer an emerging growth company. We cannot predict if investors will find our common stock less attractive because we rely and will continue to rely on these exemptions. If some investors find our common stock less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

We will cease to be an emerging growth company upon the earliest of (i) the last day of the fiscal year in which we have $1.0 billion or more in annual revenues, (ii) the date on which we become a large accelerated filer (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30), (iii) the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period, or (iv) the last day of the fiscal year following the fifth anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies. If some investors find our common stock to be less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

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If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, our shareholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common stock.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common stock.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). Forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this prospectus, are forward-looking statements. When used in this prospectus, the words could, should, will, believe, anticipate, intend, estimate, expect, may, continue, pre pursue, target, project, forecast, the negative of such terms, or other similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about:

- our business strategy;
- our estimated reserves and the present value thereof;
- our technology;
- our cash flows and liquidity;
- our financial strategy, budget, projections and future operating results;
- realized commodity prices;
- timing and amount of future production of reserves;
- availability of drilling and production equipment;
- availability of pipeline capacity;
- availability of oilfield labor;
- the amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;

drilling of wells, including statements made about future horizontal drilling activities;

competition;

government regulations;

marketing of production;

exploitation or property acquisitions;

costs of exploiting and developing our properties and conducting other operations;

general economic and business conditions;

competition in the oil and natural gas industry;

effectiveness of our risk management activities;

environmental and other liabilities;

counterparty credit risk;

taxation of the oil and natural gas industry;

developments in other countries that produce oil and natural gas;

uncertainty regarding future operating results;

plans and objectives of management; and

plans, objectives, expectations and intentions contained in this prospectus that are not historical.

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These types of statements, other than statements of historical fact included in this prospectus, are forward-looking statements. These forward-looking statements may be found in Summary, Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and other sections of this prospectus. These statements discuss future expectations, contain projections of results of operations or of financial condition or include other forward-looking information. These forward-looking statements involve risks and uncertainties. Important factors that could cause our actual results or financial condition to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

- variations in the market demand for, and prices of, oil, natural gas and NGLs;
- uncertainties about our estimated reserves;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our revolving credit facility;
- general economic and business conditions;
- risks associated with negative developments in the capital markets;
- failure to realize expected value creation from property acquisitions;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- drilling results;
- potential financial losses or earnings reductions from our commodity price risk management programs;
- adoption or potential adoption of new governmental regulations;
- the availability of capital on economic terms to fund our capital expenditures and acquisitions;
- risks associated with our substantial indebtedness; and
- our ability to satisfy future cash obligations and environmental costs.

The forward-looking statements contained in this prospectus are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this prospectus are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events or circumstances described in any forward-looking statement will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in the Risk Factors section of this prospectus and elsewhere in this prospectus. All forward-looking statements speak only as of the date on which they are made. We do not intend to update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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USE OF PROCEEDS

We will not receive any proceeds from the sale of shares of our common stock by the selling stockholders, including pursuant to any exercise by the underwriters of their option to purchase additional shares of our common stock. The selling stockholders may be deemed under federal securities laws to be underwriters with respect to the common stock they may sell in connection with this offering.

DIVIDEND POLICY

We do not anticipate declaring or providing any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain all future earnings, if any, for use in the operation of our business and to fund future growth. The decision whether to pay dividends in the future will be made by our Board in light of conditions then existing, including factors such as our financial condition, earnings, available cash, business opportunities, legal requirements, restrictions in our debt agreements, and other contracts and other factors our Board deems relevant.

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MARKET PRICE OF OUR COMMON STOCK

Our common stock began trading on the NASDAQ under the symbol MRD on June 13, 2014. Prior to that, there was no public market for our common stock. On November 12, 2014, the last reported sale price for our common stock on the NASDAQ was $23.53 per share. As of November 12, 2014, we had approximately 193,559,211 shares of common stock issued and outstanding and 64 stockholders of record. The following table sets forth, for the periods indicated, the reported high and low sale prices for our common stock on the NASDAQ.

	High	Low
Fourth Quarter 2014 (through November 12, 2014)	$ 28.44	$ 19.86
Third Quarter 2014	$ 30.32	$ 22.50
Second Quarter 2014 (beginning June 13, 2014)	$ 25.90	$ 21.07

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SELECTED HISTORICAL FINANCIAL DATA

Prior to the closing of our initial public offering, MRD LLC and its consolidated subsidiaries, our accounting predecessor, controlled MEMP through its ownership of MEMP GP, the general partner of MEMP. Because MRD LLC controlled MEMP through its ownership of the general partner, MRD LLC was required to consolidate MEMP for accounting and financial reporting purposes even though MRD LLC owned a minority of its partner interests and MRD LLC and MEMP had independent capital structures. MRD LLC received cash distributions from MEMP as a result of its partner interests and incentive distribution rights in MEMP, when declared and paid by MEMP. In connection with the closing of our initial public offering, MRD LLC contributed substantially all of its existing assets to us in exchange for shares of our common stock. Through our ownership of MEMP GP, we continue to control MEMP and therefore continue to consolidate the results of MEMP into our consolidated financial statements in current and future periods.

Our predecessor had two reportable business segments, both of which were engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

MRD reflected all of MRD LLC s consolidating subsidiaries except for MEMP and its subsidiaries.

MEMP reflected the consolidated and combined operations of MEMP and its subsidiaries.

We continue to have two reportable segments. For more information regarding reportable business segments, please see the predecessor s audited historical financial statements and related notes and our unaudited historical interim financial statements included elsewhere in this prospectus.

The following tables include selected historical financial data for us and our predecessor, as well as the MRD Segment as of and for the periods indicated. The selected historical financial data of our predecessor as of and for the years ended December 31, 2013 and 2012 were derived from the audited historical financial statements of our predecessor included elsewhere in this prospectus. The selected historical financial data as of September 30, 2014 and for the nine months ended September 30, 2014 and 2013 were derived from our unaudited interim financial statements included elsewhere in this prospectus. The selected historical financial data of the MRD Segment as of and for the years ended December 31, 2013 and 2012 were derived from certain financial information used in the preparation of our predecessor s audited financial statements. The selected historical financial data for the MRD Segment as of September 30, 2014 and for the nine months ended September 30, 2014 and 2013 were derived from certain financial information used in the preparation of our unaudited interim financial statements.

The selected unaudited pro forma data for the nine months ended September 30, 2014 and for the year ended December 31, 2013 has been prepared to give pro forma effect to: (i) the exclusion of both BlueStone and Classic Pipeline as well as the MEMP subordinated units, none of which were conveyed to us in connection with our initial public offering; (ii) certain restructuring transactions that took place in connection with our initial public offering; (iii) the MEMP Wyoming Acquisition and the MEMP Offerings; (iv) our private placement on July 10, 2014 of $600.0 million aggregate principal amount of 5.875% senior unsecured notes at par as well as MEMP s private placement on July 17, 2014 of $500.0 million aggregate principal amount of 6.875% senior unsecured notes at 98.485% of par (collectively referred to as the Debt Offerings); and (v) incremental federal income tax expense.

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We derived the data in the following tables from, and the following tables should be read together with and is qualified in its entirety by reference to, our historical financial statements (including those of our predecessor) and our pro forma financial statements and the accompanying notes included elsewhere in this prospectus. You should also read Management s Discussion and Analysis of Financial Condition and Results of Operations and our pro forma and historical consolidated financial statements, all included elsewhere in this prospectus. Among other things, those historical consolidated and combined financial statements and pro forma financial statements include more detailed information regarding the basis of presentation for the following data.

	Year Ended December 31,		Nine Months Ended September 30,		Memorial Resource Development Corp. Pro Forma	
	2013	2012	2014	2013	Year Ended December 31, 2013	Nine Months Ended September 30, 2014
	(Predecessor)			(Predecessor)		
			(unaudited)		(unaudited)	
	(in thousands)					
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$ 571,948	$ 393,631	$ 669,301	$ 420,857	$ 740,221	$ 758,811
Other revenues	3,075	3,237	3,584	1,884	2,268	3,034
Total revenues	575,023	396,868	672,885	422,741	742,489	761,845
Costs and expenses:						
Lease operating	113,640	103,754	111,887	81,746	165,092	136,561
Pipeline operating	1,835	2,114	1,596	1,343	1,835	1,596
Exploration	2,356	9,800	1,465	2,265	2,356	1,465
Production and ad valorem taxes	27,146	23,624	33,623	23,478	53,079	45,515
Depreciation, depletion and amortization	184,717	138,672	215,906	132,328	233,244	244,357
Impairment of proved oil and gas properties	6,600	28,871	67,181	21	4,201	67,181
Incentive unit compensation expense			969,390	19,069		968,367
General and administrative	125,358	69,187	61,061	55,982	101,098	61,045
Accretion of asset retirement obligations	5,581	5,009	4,601	4,016	5,803	4,741
(Gain) loss on commodity derivatives	(29,294)	(34,905)	11,580	(29,556)	(29,311)	11,580
(Gain) loss on sale of property	(85,621)	(9,761)	3,057	(86,218)	3,927	3,167
Other, net	649	502	(12)	622	649	(12)
Total costs and expenses	352,967	336,867	1,481,335	205,096	541,973	1,545,563
Operating income (loss)	222,056	60,001	(808,450)	217,645	200,516	(783,718)
Other income (expense)						
Interest expense, net	(69,250)	(33,238)	(104,928)	(41,994)	(117,843)	(108,998)
Loss on extinguishment of debt			(37,248)			(37,248)
Amortization of investment premium		(194)				
Other, net	145	535	102	81	143	102
Total other income (expense)	(69,105)	(32,897)	(142,074)	(41,913)	(117,700)	(146,144)
Income tax benefit (expense)	(1,619)	(107)	(14,398)	(1,432)	(29,814)	(21,836)
Net income (loss)	$ 151,332	$ 26,997	$ (964,922)	$ 174,300	$ 53,002	$ (951,698)
Cash Flow Data:						
Net cash provided by operating activities	$ 277,823	$ 240,404	$ 365,460	$ 237,176		
Net cash used in investing activities	367,443	606,738	1,496,677	235,883		
Net cash provided by financing activities	117,950	361,761	1,063,812	32,261		

Balance Sheet Data (at period end):			
Working capital (deficit)	$ 48,256	$ 63,054	$ (71,531)
Total assets	2,829,161	2,459,304	4,021,667
Total debt	1,663,217	939,382	2,111,800
Total equity (including noncontrolling interests)	858,132	1,276,709	1,458,999

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	MRD Segment				MRD Segment Pro Forma	
	Year Ended December 31,		Nine Months Ended September 30,		Year Ended December 31,	Nine Months Ended September 30,
	2013	2012	2014	2013	2013	2014
			(unaudited)		(unaudited)	
			(in thousands)			
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$ 230,751	$ 138,032	$ 300,931	$ 171,013	$ 212,603	$ 299,242
Other revenues	807	782	561	348		11
Total revenues	231,558	138,814	301,492	171,361	212,603	299,253
Costs and expenses:						
Lease operating	25,006	24,438	18,657	17,065	23,354	18,723
Exploration	1,226	7,337	1,213	1,137	1,226	1,213
Production and ad valorem taxes	9,362	7,576	10,494	8,563	8,485	10,443
Depreciation, depletion and amortization	87,043	62,636	107,496	62,605	76,524	106,753
Impairment of proved oil and gas properties	2,527	18,339			128	
Incentive unit compensation expense			969,390	19,069		968,367
General and administrative	81,758	38,414	29,301	22,466	57,498	29,285
Accretion of asset retirement obligations	728	632	495	547	670	495
(Gain) loss on commodity derivatives	(3,013)	(13,488)	(17,130)	(8,361)	(3,030)	(17,130)
(Gain) loss on sale of property	(82,773)	(2)	3,057	(83,370)	6,775	3,167
Other, net	2	364		(25)	2	
Total costs and expenses	121,866	146,246	1,122,973	39,696	171,632	1,121,316
Operating income (loss)	109,692	(7,432)	(821,481)	131,665	40,971	(822,063)
Other income (expense)						
Interest expense, net	(27,349)	(12,802)	(44,355)	(15,947)	(45,972)	(32,151)
Loss on extinguishment of debt			(37,248)			(37,248)
Earnings from equity investments	1,066	4,880	(12,844)	(24)	269	18
Other, net	145	535	102	81	143	102
Total other income (expense)	(26,138)	(7,387)	(94,345)	(15,890)	(45,560)	(69,279)
Income tax (expense) benefit	(1,311)	178	(14,323)	(1,147)	1,652	(23,137)
Net income (loss)	$ 82,243	$ (14,641)	$ (930,149)	$ 114,628	$ (2,937)	$ (914,479)
Cash Flow Data (Unaudited):						
Net cash provided by operating activities	$ 83,910	$ 84,172	$ 181,683	$ 90,118		
Net cash used in investing activities	5,533	230,471	215,139	26,382		
Net cash provided by (used in) financing activities	(38,963)	133,271	(21,388)	(21,378)		
Other Financial Data:						
Adjusted EBITDA (unaudited)	$ 197,903	$ 132,105	$ 247,335	$ 153,679	$ 159,239	$ 258,982
Balance Sheet Data (at period end):						
Working capital (unaudited)	$ 51,214	$ 2,424	$ (17,799)			
Total assets	1,281,134	1,102,406	1,232,146			
Total debt	871,150	309,200	628,000			
Total equity (unaudited)	279,412	682,644	436,231			

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the financial statements and related notes included elsewhere in this prospectus. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences are described under the heading Risk Factors included elsewhere in this prospectus. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. Also see Cautionary Note Regarding Forward-Looking Statements included elsewhere in this prospectus.

Overview

We are a Delaware corporation, formed by Memorial Resource Development LLC (MRD LLC) in January 2014, engaged in the acquisition, exploitation, and development of natural gas, NGL and oil properties primarily in North Louisiana and East Texas. MRD LLC, our accounting predecessor, was a Delaware limited liability company formed on April 27, 2011 by Natural Gas Partners VIII, L.P. (NGP VIII), Natural Gas Partners IX, L.P. (NGP IX) and NGP IX Offshore Holdings, L.P. (NGP IX Offshore) (collectively, the Funds) to own, acquire, exploit and develop oil and natural gas properties. The Funds are private equity funds managed by Natural Gas Partners (NGP).

We completed our initial public offering on June 18, 2014. In connection with the closing of our initial public offering, MRD LLC contributed to us substantially all of its assets, comprised of the following, in exchange for shares of our common stock (which were distributed to MRD LLC s sole member, MRD Holdco LLC (MRD Holdco)): (1) 100% of its ownership interests in Classic Hydrocarbons Holdings, L.P. (Classic), Classic Hydrocarbons GP Co., L.L.C. (Classic GP), Black Diamond Minerals, LLC (Black Diamond), Beta Operating Company, LLC (Beta Operating), MRD Operating LLC (MRD Operating) and Memorial Production Partners GP LLC (MEMP GP), which owns a 0.1% general partner interest and 50% of the incentive distribution rights in Memorial Production Partners LP (MEMP), and (2) its 99.9% membership interest in WildHorse Resources, LLC (WildHorse Resources). In addition, certain former management members of WildHorse Resources contributed to us the remaining 0.1% membership interest in WildHorse Resources, and also exchanged their incentive units in WildHorse Resources, for shares of our common stock and cash consideration. As a result, we are majority-owned by the group consisting of MRD Holdco and certain former management members of WildHorse Resources.

Following the completion of our initial public offering, MRD LLC distributed to MRD Holdco (i) its interests in BlueStone Natural Resources Holdings, LLC (BlueStone), MRD Royalty LLC (MRD Royalty), MRD Midstream LLC (MRD Midstream), Golden Energy Partners LLC (Golden Energy) and Classic Pipeline & Gathering, LLC (Classic Pipeline), (ii) the MEMP subordinated units; (iii) the remaining cash released from its debt service reserve account in connection with the redemption of the 10.00% /10.75% Senior PIK Toggle Notes due 2018 (the PIK notes); and (iv) approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy s assets in May 2014. We also reimbursed MRD LLC for the approximately $17.2 million interest payment that it made on the PIK notes on June 15, 2014, which was distributed to MRD Holdco.

As part of the restructuring transactions, we merged Black Diamond into MRD Operating in connection with the completion of our initial public offering, and MRD LLC was merged into MRD Operating upon the termination of the PIK notes indenture on June 27, 2014.

We control MEMP through the ownership of MEMP GP. MEMP is a publicly traded limited partnership engaged in the acquisition, production and development of oil and natural gas properties in the United States.

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Due to our control of MEMP through the ownership of MEMP GP, we are required to consolidate MEMP for accounting and financial reporting purposes. Although consolidated for accounting and financial reporting, we each have independent capital structures. MRD LLC previously received cash distributions from MEMP as a result of its partner interests and incentive distribution rights in MEMP, when declared and paid by MEMP. We will continue to receive cash distributions from MEMP as a result of our 0.1% general partner interest and incentive distribution rights in MEMP, when declared and paid by MEMP.

Business Segments

Our reportable business segments are organized in a manner that reflects how management manages those business activities. We evaluate segment performance based on Adjusted EBITDA. For additional information regarding this financial measure, see Summary Historical Consolidated and Combined Pro Forma Financial Data Adjusted EBITDA.

We have two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties. Our reportable business segments are as follows:

- MRD reflects the combined operations of the Company, MRD LLC, WildHorse Resources and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.
- MEMP reflects the combined operations of MEMP, its previous owners, and historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

Segment financial information has been retrospectively revised for the following common control transactions between MEMP and MRD LLC for comparability purposes:

- acquisition by MEMP of all the outstanding membership interests in Tanos Energy, LLC (Tanos) for a purchase price of approximately $77.4 million on October 1, 2013;
- acquisition by MEMP of all the outstanding membership interests in Prospect Energy, LLC (Prospect Energy) from Black Diamond for a purchase price of approximately $16.3 million on October 1, 2013;
- acquisition by MEMP of certain of the oil and natural gas properties in Jackson County, Texas from MRD LLC for a purchase price of approximately $2.6 million on October 1, 2013; and
- acquisition by MEMP of all the outstanding membership interests in WHT Energy Partners LLC (WHT) for a purchase price of approximately $200.0 million on March 28, 2013.

The MRD Segment is focused on the exploitation, development, and acquisition of natural gas, NGL and oil properties mainly in the Cotton Valley formation in North Louisiana and East Texas as well as the Rocky Mountains. These properties consist primarily of assets with extensive production histories, high drilling success rates, and significant horizontal redevelopment potential. The MRD Segment is focused on maintaining and growing its production and cash flow primarily through the development of its sizeable inventory. The MRD Segment, prior to our initial public offering, included BlueStone, MRD Royalty, MRD Midstream, Golden Energy, Classic Pipeline, the MEMP subordinated units and cash held in a debt service reserve account that had been established when the PIK notes were issued in December 2013.

The MEMP Segment is engaged in the acquisition, exploitation, development and production of oil and natural gas properties, with assets consisting primarily of producing oil and natural gas properties that are principally located in East Texas/North Louisiana, the Rockies, South Texas, the Permian and offshore Southern California. Most of the MEMP Segment s properties are located in large, mature oil and natural gas reservoirs with well-known geologic characteristics and long-lived, predictable production profiles and modest capital requirements. The MEMP Segment is focused on generating stable cash flows to allow MEMP to make quarterly cash distributions to its unitholders and, over time, to increase those quarterly cash distributions.

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Recent Developments

MRD Segment

On June 18, 2014, we completed our initial public offering pursuant to which we sold 21,500,000 shares of our common stock to the public at an offering price of $19.00 per share. We received net proceeds of approximately $380.2 million, after deducting underwriting discounts and commissions and fees and expenses associated with the offering and the restructuring transactions entered into in connection with the offering. We used approximately $360.0 million of our initial public offering proceeds to redeem the PIK notes on June 27, 2014. In addition, MRD Holdco sold 27,720,000 shares of our common stock in our initial public offering as a selling stockholder. We did not receive any proceeds from the sale of shares by MRD Holdco.

On July 10, 2014, we completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes (the MRD Senior Notes) at par. The MRD Senior Notes will mature on July 1, 2022. Interest on the MRD Senior Notes will accrue from July 10, 2014 and will be payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2015. The net proceeds of approximately $586.0 million, after deducting the initial purchasers discounts and commissions and estimated offering expenses, were used to repay a portion of the borrowings outstanding under our revolving credit facility. The amounts repaid under our revolving credit facility were incurred to repay the amounts outstanding under WildHorse Resources credit facilities in connection with the closing of our initial public offering. In conjunction with the closing of the offer and sale of the MRD Senior Notes, the borrowing base under MRD s revolving credit facility was automatically decreased by $56.5 million.

MEMP Segment

On July 1, 2014, MEMP acquired certain oil and natural gas liquids properties in Wyoming (the MEMP Wyoming Acquisition) from Merit Energy Company, LLC and certain of its affiliates (Merit) for an aggregate adjusted purchase price of approximately $911.7 million, including estimated customary post-closing adjustments. The MEMP Wyoming Acquisition had an effective date of April 1, 2014. In conjunction with the closing of the MEMP Wyoming Acquisition, the borrowing base under MEMP s revolving credit facility was increased from $870 million to $1.44 billion. The MEMP Wyoming Acquisition was funded with borrowings under MEMP s revolving credit facility.

On July 15, 2014, MEMP issued 9,890,000 common units representing limited partner interests in MEMP (including 1,290,000 common units purchased pursuant to the full exercise of the underwriters option to purchase additional common units) to the underwriters at a negotiated price of $22.25 per unit generating total net proceeds of approximately $220.0 million after offering expenses. The net proceeds from this equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility.

On July 17, 2014, MEMP and its wholly-owned subsidiary Memorial Production Finance Corporation (Finance Corp. and, together with MEMP, the MEMP Issuers) completed a private placement of $500.0 million aggregate principal amount of 6.875% senior unsecured notes due 2022 (the 2022 Senior Notes). The 2022 Senior Notes were issued at 98.485% of par and are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by all of the MEMP s subsidiaries (other than Finance Corp., which is co-issuer of the 2022 Senior Notes, and certain immaterial subsidiaries). The 2022 Senior Notes will mature on August 1, 2022 with interest accruing at 6.875% per annum and payable semi-annually in arrears on February 1 and August 1 of each year, commencing on February 1, 2015. The net proceeds of approximately $484.9 million, after deducting the initial purchasers discounts and commissions but before estimated offering expenses, were used to repay a portion of the borrowings outstanding under MEMP s revolving credit facility and for general partnership purposes. In conjunction with the closing of the offer and sale of the 2022 Senior Notes, the borrowing base under MEMP s revolving credit facility was automatically decreased from $1.440 billion to $1.315 billion.

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On September 9, 2014, MEMP issued 14,950,000 common units representing limited partner interests in MEMP (including 1,950,000 common units purchased pursuant to the full exercise of the underwriters option to purchase additional common units) to the public at an offering price of $22.29 per unit generating total net proceeds of approximately $321.6 million after underwriting discounts and commissions and offering expenses. The net proceeds from this equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility

Sources of Revenues

Both the MRD Segment s and the MEMP Segment s revenues are derived from the sale of natural gas and oil production, as well as the sale of NGLs that are extracted from natural gas during processing. Production revenues are derived entirely from the continental United States. Natural gas, NGL and oil prices are inherently volatile and are influenced by many factors outside our control. In order to reduce the impact of fluctuations in natural gas and oil prices on revenues, or to protect the economics of property acquisitions, both segments intend to periodically enter into derivative contracts with respect to a significant portion of their estimated natural gas and oil production through various transactions that fix the future prices received. These transactions may include price swaps whereby the applicable segment will receive a fixed price for production and pay a variable market price to the contract counterparty. Additionally, either segment may enter into costless collars, whereby the applicable segment receives the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. At the end of each period the fair value of these commodity derivative instruments are estimated and, because hedge accounting is not elected, the changes in the fair value of unsettled commodity derivative instruments are recognized in earnings at the end of each accounting period.

Principal Components of Cost Structure

Lease operating expenses. These are the day to day costs incurred to maintain production of our natural gas, NGLs and oil. Such costs include utilities, direct labor, water injection and disposal, materials and supplies, compression, repairs and workover expenses. Cost levels for these expenses can vary based on supply and demand for oilfield services.

Production and ad valorem taxes. These consist of severance and ad valorem taxes. Production taxes are paid on produced natural gas, NGLs and oil based on a percentage of market prices and at fixed per unit rates established by federal, state or local taxing authorities. Both the MRD and MEMP Segments take full advantage of all credits and exemptions in the various taxing jurisdictions where they operate. Ad valorem taxes are generally tied to the valuation of the oil and natural properties; however, these valuations are reasonably correlated to revenues, excluding the effects of any commodity derivative contracts.

Exploration expense. These are geological and geophysical costs and include seismic costs, costs of unsuccessful exploratory dry holes and unsuccessful leasing efforts.

Impairment of unproved and proved properties. For unproved properties, these primarily include costs associated with lease expirations. Proved properties are impaired whenever the carrying value of the properties exceed their estimated undiscounted future cash flows.

Depreciation, depletion and amortization. Depreciation, depletion and amortization, or DD&A, includes the systematic expensing of the capitalized costs incurred to acquire, exploit and develop natural gas, NGLs and oil. As a successful efforts company, all costs associated with acquisition and development efforts and all successful exploration efforts are capitalized, and these costs are depleted using the units of production method.

Incentive unit compensation expense. For more information regarding compensation expense recognized associated with incentive units, see Note 12 of the Notes to Unaudited Condensed Consolidated and Combined Financial Statements.

General and administrative expense. These costs include overhead, including payroll and benefits for employees, costs of maintaining headquarters, costs of managing production and development operations,

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compensation expense associated with certain long-term incentive-based plans, franchise taxes, audit and other professional fees, and legal compliance expenses.

Interest expense. Both the MRD and MEMP Segments finance a portion of their working capital requirements and acquisitions with borrowings under revolving credit facilities and senior note issuances. As a result, both the MRD and MEMP Segments incur substantial interest expense that is affected by both fluctuations in interest rates and financing decisions. We expect to continue to incur significant interest expense as we continue to grow.

Income tax expense. Prior to our initial public offering, MRD LLC was organized as a pass-through entity for federal income tax purposes and was not subject to federal income taxes; however, certain of its consolidating subsidiaries were taxed as corporations and subject to federal income taxes. We are organized as a taxable C corporation and subject to federal and certain state income taxes. We are also subject to the Texas margin tax and certain aspects of the tax make it similar to an income tax as the tax is assessed on 1% of taxable margin apportioned to operations in Texas.

Results of Operations

Consolidated

Selected consolidated and combined results of operations for the years ended December 31, 2013 and 2012 and the nine months ended September 30, 2014 and 2013 are presented below and have been derived from our predecessor s and our consolidated and combined financial statements included elsewhere in this prospectus. Also see our predecessor s consolidated and combined financial statements and related notes included elsewhere in this prospectus for a description of our predecessor s previous owners.

	For Year Ended December 31,		For Nine Months Ended September 30,	
	2013	2012	2014	2013
			(unaudited)	
Oil and natural gas sales	$ 571,948	$ 393,631	$ 669,301	$ 420,857
Lease operating	113,640	103,754	111,887	81,746
Exploration	2,356	9,800	1,465	2,265
Production and ad valorem taxes	27,146	23,624	33,623	23,478
Depreciation, depletion and amortization	184,717	138,672	215,906	132,328
Incentive unit compensation expense			67,181	21
Impairment of proved oil and gas properties	6,600	28,871	969,390	19,069
General and administrative	125,358	69,187	61,061	55,982
(Gain) loss on commodity derivative instruments	(29,294)	(34,905)	11,580	(29,556)
(Gain) loss on sale of properties	(85,621)	(9,761)	3,057	(86,218)
Interest expense, net	69,250	33,238	(104,928)	(41,994)
Loss on extinguishment of debt			(37,248)	
Net income (loss)	151,332	26,997	(964,922)	174,300

Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

Our predecessor recorded net income of $151.3 million in 2013 compared to net income of $27.0 million in 2012. The increase in net income was primarily due to increases in revenues and gains on the sale of properties, partially offset by increases in DD&A, general and administrative expenses and interest expense.

Oil and natural gas revenues were $571.9 million, an increase of $178.3 million from 2012. Production increased 28,062 MMcfe (approximately 37%) while the average realized sales price increased $0.31 per Mcfe. Production increases were primarily due to acquisitions and drilling activities in North Louisiana and East Texas. The favorable volume variance contributed to a $147.2 million increase in revenues and the favorable pricing variance contributed to a $31.1 million increase in revenues.

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The $46.0 million increase in DD&A expense was primarily due to increased production volumes related to acquisitions and drilling activities in North Louisiana and East Texas. Increased production volumes increased DD&A expense by $51.8 million, while a 3% decrease in the DD&A rate between periods decreased DD&A expense by $5.8 million.

During 2013, BlueStone sold its remaining interests in certain properties in East Texas to a third party and recognized a gain of $89.5 million. This gain was partially offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain of its Wyoming properties. During 2012, the previous owners of oil and gas properties acquired by MEMP recognized a gain of approximately $9.8 million related to the sale of properties in West Texas.

Interest expense was $69.3 million in 2013, an increase of $36.0 million from 2012. The increase in interest expense was primarily due to higher levels of indebtedness as debt outstanding was $939.4 million at December 31, 2012 compared to $1,663.2 million at December 31, 2013.

Please see segment discussion below for further information regarding changes in other line items on a segment basis.

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

A net loss of $964.9 million was generated for the nine months ended September 30, 2014 compared to net income of $174.3 million for nine months ended September 30, 2013. The net loss recorded during 2014 was primarily due to compensation expense recognized associated with incentive units as discussed below.

Oil, natural gas and NGL revenues for 2014 totaled $669.3 million, an increase of $248.4 million compared with 2013. Production increased 33.9 Bcfe (approximately 45%) primarily due to acquisitions and drilling activities in North Louisiana and East Texas. The average realized sales price increased $0.53 per Mcfe primarily due to higher natural gas prices. The favorable volume and pricing variance contributed to an approximate $190.3 million and $58.2 million increase in revenues, respectively.

Lease operating expenses were $111.9 million and $81.7 million for 2014 and 2013, respectively, an increase of $30.2 million primarily due to increased production volumes. On a per Mcfe basis, lease operating expenses decreased to $1.03 for 2014 from $1.09 for 2013. During 2014, MEMP recorded $2.9 million of estimated environmental remediation expenses associated with its Permian and Wyoming oil and gas properties.

DD&A expense for 2014 was $215.9 million compared to $132.3 million for 2013, a $83.6 million increase primarily due to both an increase in the depletable cost base and increased production volumes related to acquisitions and drilling activities in North Louisiana and East Texas. Increased production volumes caused DD&A expense to increase by an approximate $59.8 million and the change in the DD&A rate between periods caused DD&A expense to increase by an approximate $23.8 million.

Impairments for 2014 totaled $67.2 million primarily related to certain MEMP properties located in South Texas. The estimated future cash flows expected for these properties were compared to their carrying values and determined to be unrecoverable in part due to a downward revision of estimated proved reserves based on declining commodity prices and increased operating costs. We recognized impairment charges of less than $0.1 million on a consolidated basis for 2013.

Incentive unit compensation expense for 2014 was $969.4 million, of which $831.1 million related to WildHorse Resources incentive units, $137.3 million related to MRD Holdco incentive units, and $1.0 million related to BlueStone incentive units. Incentive unit compensation expense of approximately $19.1 million was recorded by BlueStone in 2013. Net proceeds generated from the sale of oil and gas properties were used to pay a distribution to BlueStone incentive unit holders. For more information regarding the recognition of compensation expense associated with incentive units during 2014, see Note 12 of the Notes to Unaudited Condensed Consolidated and Combined Financial Statements included elsewhere in this prospectus.

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General and administrative expenses for 2014 were $61.1 million compared to $56.0 million for 2013. General and administrative expenses for 2014 included $6.9 million of compensation expense associated with long-term incentive plans and $5.5 million of acquisition-related costs. General and administrative expenses for 2013 included $5.8 million recorded by Tanos associated with incentive units forfeited, $2.3 million of compensation expense associated with long-term incentive plans and $5.1 million of acquisition-related costs. Increased salaries and employee headcount also contributed to increased general and administrative expenses between periods. For more information regarding the recognition of compensation expense associated with long-term incentive plans and incentive units, see Notes 11 and 12 of the Notes to Unaudited Condensed Consolidated and Combined Financial Statements included elsewhere in this prospectus.

Net losses on commodity derivative instruments of $11.6 million were recognized during 2014, consisting of $19.9 million of cash settlement payouts, offset by a $8.3 million increase in the fair value of open hedge positions. Net gain on commodity derivative instruments of $29.6 million were recognized during 2013, consisting of $23.2 million of cash settlement receipts in addition to a $6.4 million increase in the fair value of open hedge positions.

Interest expense was $104.9 million during 2014, an increase of $62.9 million from 2013. The increase in interest expense was primarily due to higher levels of indebtedness. The mix of debt was also a contributing factor. The MRD Senior Notes, MEMP s 2022 Senior Notes and MEMP s 2021 Senior Notes carry a higher interest rate compared to debt under revolving credit facilities.

We irrevocably deposited with the PIK notes trustee approximately $360.0 million on June 27, 2014, which was an amount sufficient to fund the redemption of the PIK notes on the redemption date and to satisfy and discharge our obligations under the PIK notes and the related indenture. The discharge became effective upon the irrevocable deposit of the funds with the PIK notes trustee. An extinguishment loss of $23.6 million was recognized related to the redemption of the PIK notes.

In connection with the closing of our initial public offering, the WildHorse Resources revolving credit facility and second lien term loan were repaid in full and terminated. An extinguishment loss of $13.7 million was recognized related to the termination of the revolving credit facility and second lien term loan.

During 2013, BlueStone entered into an agreement with a third party to sell its remaining interest in certain properties and recognized a gain of $90.1 million. This gain was partially offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain oil and gas properties.

Please see segment discussion below for further information regarding changes in other line items on a segment basis.

MRD Segment

The MRD Segment s consolidated and combined results of operations for the years ended December 31, 2013 and 2012 and the nine months ended September 30, 2014 and 2013 presented below have been derived from our predecessor s and our consolidated and combined financial statements. The comparability of the results of operations among the periods presented is impacted by the following significant transactions:

- the sale of assets by BlueStone in East Texas in July 2013 for approximately $117.9 million;

- the acquisition by WildHorse Resources of assets in Louisiana in March 2013 for approximately $67.1 million; and the distribution by MRD LLC of the following to MRD Holdco: (i) BlueStone, which sold substantially all of its assets in July 2013 for $117.9 million, MRD Royalty LLC, which owns certain immaterial leasehold interests and overriding royalty interests in Texas and Montana, MRD Midstream LLC, which owns an indirect interest in certain midstream assets in North Louisiana, Golden Energy and Classic Pipeline and (ii) 5,360,912 subordinated units of MEMP.

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Segment financial information has been retrospectively revised for material common control transactions between MEMP and MRD LLC for comparability purposes, which includes the following transactions:

- acquisition by MEMP of all the outstanding membership interests in Tanos for a purchase price of approximately $77.4 million on October 1, 2013;
- acquisition by MEMP of all the outstanding membership interests in Prospect from Black Diamond for a purchase price of approximately $16.3 million on October 1, 2013;
- acquisition by MEMP of certain of the oil and natural gas properties in Jackson County, Texas from MRD LLC for a purchase price of approximately $2.6 million on October 1, 2013; and
- acquisition by MEMP of all the outstanding membership interests in WHT for a purchase price of approximately $200.0 million on March 28, 2013.

	For Year Ended December 31,		For Nine Months Ended September 30, (unaudited)	
	2013	2012	2014	2013
Oil and natural gas sales	$ 230,751	$ 138,032	$ 300,931	$ 171,013
Lease operating	25,006	24,438	18,657	17,065
Exploration	1,226	7,337	1,213	1,137
Production and ad valorem taxes	9,362	7,576	10,494	8,563
Depreciation, depletion and amortization	87,043	62,636	107,496	62,605
Incentive unit compensation cost			969,390	19,069
Impairment of proved oil and natural gas properties	2,527	18,339		
General and administrative	81,758	38,414	29,301	22,466
(Gain) loss on commodity derivative instruments	(3,013)	(13,488)	(17,130)	(8,361)
(Gain) loss on sale of properties	(82,773)	(2)	3,057	(83,370)
Interest expense, net	27,349	12,802	(44,355)	(15,947)
Loss on extinguishment of debt			(37,248)	
Income tax benefit (expense)			(14,323)	(1,147)
Net income (loss)	82,243	(14,641)	(930,149)	114,628
Natural gas and oil revenue:				
Oil sales	$ 66,961	$ 35,264	$ 66,495	$ 50,683
NGL sales	53,881	36,611	67,539	37,311
Natural gas sales	109,909	66,157	166,897	83,019
Total natural gas and oil revenue	$ 230,751	$ 138,032	$ 300,931	$ 171,013
Production Volumes:				
Oil (MBbls)	665	369	689	498
NGLs (MBbls)	1,457	898	1,612	990
Natural gas (MMcf)	34,092	24,130	43,075	25,164
Total (MMcfe)	46,819	31,731	56,869	34,075
Average net production (MMcfe/d)	128.3	86.7	208.3	124.8
Average sales price:				

Oil (Bbl)	$ 100.76	$ 95.56	$ 96.60	$ 101.77
NGL (Bbl)	36.99	40.78	41.93	37.69
Natural gas (per Mcf)	3.22	2.74	3.87	3.30
Total (Mcfe)	$ 4.93	$ 4.35	$ 5.29	$ 5.02
Average unit costs per Mcfe:				
Lease operating expense	$ 0.53	$ 0.77	$ 0.33	$ 0.50
Production and ad valorem taxes	$ 0.20	$ 0.24	$ 0.18	$ 0.25
General and administrative expenses	$ 1.75	$ 1.21	$ 0.52	$ 0.66
Depletion, depreciation, and amortization	$ 1.86	$ 1.97	$ 1.89	$ 1.84

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Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

The MRD Segment recorded net income of $82.2 million in 2013 compared to a net loss of $14.6 million in 2012. The increase in net income was primarily due to gains on sales of properties and increased production.

Oil and natural gas revenues were $230.8 million in 2013, an increase of $92.7 million from 2012. Production increased 15,088 MMcfe (approximately 48%) while the average realized sales price increased $0.58 per Mcfe. Production volume increases were primarily due to acquisitions and drilling activities in the Cotton Valley formation in North Louisiana and East Texas. The favorable volume variance contributed to a $65.6 million increase in revenues, and the favorable pricing variance contributed to a $27.1 million increase in revenues.

Lease operating expenses were $25.0 million in 2013, an increase in $0.6 million from 2012. This increase was primarily due to acquisitions and drilling activities in the Cotton Valley formation in North Louisiana and East Texas. However, on a per Mcfe basis, lease operating expenses decreased by $0.24 per Mcfe as certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges.

The $24.4 million increase in DD&A expense was primarily due to increased production volumes related to acquisitions and drilling activities in the Cotton Valley formation in North Louisiana and East Texas. Increased production volumes increased DD&A expense by $29.8 million, while a 6% decrease in the DD&A rate between periods decreased DD&A expense by $5.4 million. On a per Mcfe basis, DD&A expense decreased by $0.11 per Mcfe from 2012 to 2013. An increase in proved reserve volumes more than offset the impact of increases to the depletable cost base. Generally, if reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, if the depletable base changes, then the DD&A rate moves in the same direction. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes.

During 2013 and 2012, the MRD Segment recorded impairments of $2.5 million and $18.3 million, respectively, primarily related to certain fields in East Texas. For these impairments, the estimated future cash flows expected from properties in these fields were compared to their carrying values and determined to be unrecoverable. Downward revisions due to performance and declines in natural gas prices triggered the 2013 and 2012 impairments, respectively.

General and administrative expenses were $81.8 million in 2013, an increase of $43.3 million from 2012. The increase in general and administrative expenses was primarily due to growth in employees as a result of acquisitions and development activities and incentive unit compensation expense. General and administrative expenses during 2013 included recognition of approximately $43.3 million of compensation expense related to incentive unit payments to certain key management members of certain MRD LLC subsidiaries compared to approximately $9.5 million recorded in 2012.

Gains on commodity derivative instruments of $3.0 million were recognized during 2013, of which $12.2 million consisted of cash settlements received. Gains on commodity derivative instruments of $13.5 million were recognized during 2012, of which $30.2 million consisted of cash settlements received. The decrease in cash settlements received was primarily due to higher natural gas prices.

Given the volatility of commodity prices, it is not possible to predict future changes in fair value or cash settlements that will ultimately be realized upon settlement of the open positions in future years. If commodity prices at settlement are lower than the prices of the settled positions, the derivative contracts are expected to mitigate the otherwise negative effect on earnings of lower oil, natural gas and NGL prices. However, if commodity prices at settlement are higher than the prices of the settled positions, the derivative contracts are expected to dampen the otherwise positive effect on earnings of higher oil, natural gas and NGL prices and will, in this context, be viewed as having resulted in an opportunity cost.

During 2013, BlueStone entered into an agreement with a publicly traded third party to sell its remaining interest in certain properties in the Mossy Grove Prospect in Walker and Madison Counties located in East

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Texas and recognized a gain of $89.5 million. This gain was offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain of its Wyoming oil and gas properties. During 2012, gains of less than $0.1 million were recognized by the MRD Segment.

Net interest expense during 2013 was $27.3 million, including amortization of deferred financing fees of approximately $2.5 million and losses on interest rate swaps of $0.2 million. Net interest expense during 2012 was $12.8 million, including amortization of deferred financing fees of approximately $1.6 million and losses on interest rate swaps of $1.2 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2013 compared to 2012.

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

The MRD Segment recorded a net loss of $930.1 million during 2014 compared to net income of $114.6 million during 2013. The net loss recorded during 2014 was primarily due to compensation expense recognized associated with incentive units as discussed below.

Oil, natural gas and NGL revenues for 2014 totaled $300.9 million, an increase of $129.9 million compared with 2013. Production increased 22.8 Bcfe (approximately 67%) primarily due to drilling activities in North Louisiana and East Texas. The average realized sales price increased $0.27 per Mcfe primarily due to higher natural gas and NGL prices. The favorable volume and pricing variance contributed to an approximate $114.4 million and $15.5 million increase in revenues, respectively.

Lease operating expenses were $18.7 million and $17.1 million for 2014 and 2013, respectively. On a per Mcfe basis, lease operating expenses decreased to $0.33 for 2014 from $0.50 for 2013. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges.

DD&A expense for 2014 was $107.5 million compared to $62.6 million for 2013, a $44.9 million increase primarily due to both an increase in the depletable cost base and increased production volumes related to drilling activities in North Louisiana and East Texas. Increased production volumes caused DD&A expense to increase by an approximate $41.9 million and the change in the DD&A rate between periods caused DD&A expense to decrease by an approximate $3.0 million.

Incentive unit compensation expense for 2014 was $969.4 million, of which $831.1 million related to WildHorse Resources incentive units, $137.3 million related to MRD Holdco incentive units, and $1.0 million related to BlueStone incentive units as previously discussed above. Incentive unit compensation expense of approximately $19.1 million was recorded by BlueStone in 2013. Net proceeds generated from the sale of oil and gas properties were used to pay a distribution to BlueStone incentive unit holders.

General and administrative expenses for 2014 were $29.3 million compared to $22.5 million for 2013. General and administrative expenses for 2014 included $1.5 million of compensation expense associated with the MRD LTIP and $1.6 million of acquisition-related costs. General and administrative expenses for 2013 included $1.7 million of acquisition-related costs. Increased salaries and employee headcount also contributed to increased general and administrative expenses between periods.

Net gains on commodity derivative instruments of $17.1 million were recognized during 2014, consisting of $4.9 million of cash settlement payouts offset by a $22.0 million increase in the fair value of open hedge positions. Net gains on commodity derivative instruments of $8.4 million were recognized during 2013, consisting of $9.1 million of cash settlement receipts offset by a $0.7 million decrease in the fair value of open hedge positions.

Net interest expense during 2014 was $44.4 million, including amortization of deferred financing fees of approximately $2.6 million and accretion of discount associated with the PIK notes of $0.6 million. Net interest expense during 2013 was $15.9 million, including amortization of deferred financing fees of approximately $1.7 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2014 compared to 2013, including the MRD Senior Notes.

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During 2013, BlueStone entered into an agreement with a third party to sell its remaining interest in certain properties and recognized a gain of $90.1 million. This gain was offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain oil and gas properties.

We are organized as a taxable C corporation and subject to federal and certain state income taxes. We recorded tax expense of $14.3 million in 2014 subsequent to our initial public offering.

MEMP Segment

The MEMP Segment s consolidated and combined results of operations for the years ended December 31, 2013 and 2012 and the nine months ended September 30, 2014 and 2013 presented below have been derived from our and our predecessor s consolidated and combined financial statements included elsewhere in this prospectus.

The comparability of the results of operations among the periods presented is impacted by the following significant transactions:

- two separate third party acquisitions by MEMP of assets in East Texas in May and September 2012, respectively, for a combined net purchase price of approximately $126.9 million;

- the acquisition of working interests, royalty interests and net revenue interests located in the Permian Basin in July 2012 for a net purchase price of approximately $74.7 million;

- multiple acquisitions of operated and non-operated interests in certain oil and natural gas properties primarily located in the Permian Basin for an aggregate net purchase price of $75.9 million;

- the acquisition of certain oil and natural gas properties in the Eagle Ford trend from Alta Mesa Holdings, LP in March 2014 for an adjusted purchase price of $168.1 million; and

- the completion of the MEMP Wyoming Acquisition on July 1, 2014 for an aggregate purchase price of approximately $911.7 million, including estimated customary post-closing adjustments.

	For Year Ended December 31, 2013	2012	For Nine Months Ended September 30, 2014 (unaudited)	2013
Oil & natural gas sales	$ 341,197	$ 255,608	$ 368,370	$ 249,844
Lease operating	88,893	80,116	93,367	64,922
Exploration	1,130	2,463	252	1,128
Production and ad valorem taxes	17,784	16,048	23,129	14,915
Depreciation, depletion and amortization	97,269	76,036	105,830	69,723
Impairment of proved oil and natural gas properties	54,362	10,532	67,181	50,310
General and administrative	43,495	30,342	31,760	33,411
(Gain) loss on commodity derivative instruments	(26,281)	(21,417)	28,710	(21,195)
(Gain) loss on sale of properties	(2,848)	(9,759)		(2,848)
Interest expense, net	41,901	20,436	(60,573)	(26,047)
Net income (loss)	20,268	46,518	(45,037)	9,359
Natural gas and oil revenue:				
Oil sales	$ 171,095	$ 145,103	$ 192,086	$ 127,436
NGL sales	51,215	26,647	48,958	35,202
Natural gas sales	118,887	83,858	127,326	87,206
Total natural gas and oil revenue	$ 341,197	$ 255,608	$ 368,370	$ 249,844
Production Volumes:				
Oil (MBbls)	1,764	1,519	2,056	1,307
NGLs (MBbls)	1,632	745	1,498	1,147
Natural gas (MMcf)	35,924	29,744	30,625	26,137
Total (MMcfe)	56,303	43,329	51,946	40,861
Average net production (MMcfe/d)	154.3	118.4	190.3	149.7
Average sales price:				
Oil (Bbl)	$ 96.98	$ 95.54	$ 93.45	$ 97.50
NGL (Bbl)	31.38	35.75	32.69	30.69
Natural gas (per Mcf)	3.31	2.82	4.16	3.34
Total (Mcfe)	$ 6.06	$ 5.90	$ 7.09	$ 6.11
Average unit costs per Mcfe:				
Lease operating expense	$ 1.58	$ 1.85	$ 1.80	$ 1.59
Production and ad valorem taxes	$ 0.32	$ 0.37	$ 0.45	$ 0.37
General and administrative expenses	$ 0.77	$ 0.70	$ 0.61	$ 0.82
Depletion, depreciation, and amortization	$ 1.73	$ 1.75	$ 2.04	$ 1.71

Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

MEMP recorded net income of $20.3 million in 2013 compared to income of $46.5 million in 2012.

Oil and natural gas revenues were $341.2 million in 2013, an increase of $85.6 million from 2012. Production increased 12,974 MMcfe (approximately 30%) while the average realized sales price increased $0.16 per Mcfe. The favorable volume variance contributed to a $76.6 million increase in revenues, whereas the favorable pricing variance contributed to a $9.0

million decrease in revenues.

Lease operating expenses were $88.9 million in 2013, an increase of $8.8 million from 2012. Production and ad valorem taxes were $17.8 million in 2013, an increase of $1.7 million from 2012. Both lease operating expenses and production and ad valorem taxes increased primarily due to increased production volumes associated with properties acquired during both 2012 and 2013 and increased drilling activities.

The increase in DD&A expense was primarily due to increased production volumes related to acquisitions in 2012 and 2013 and increased drilling activities. Increased production volumes caused DD&A expense to increase by $22.8 million, while a 1% change in the DD&A rate between periods caused DD&A expense to decrease by $1.5 million. An increase in proved reserve volumes more than offset the impact of increases to the depletable cost base.

During 2013, MEMP recorded $54.4 million of impairments consisting of $50.3 million related to certain properties in East Texas and $4.1 million related to certain properties in South Texas. For the East Texas properties, the estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of downward revisions of estimated proved reserves based upon updated well performance data. In South Texas, the estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on pricing terms specific to these properties. During 2012, MEMP recorded impairments of $10.5 million primarily related to properties in the Permian Basin. The 2012 impairments were a result of downward revisions of estimated proved reserves due to unfavorable drilling results in the area.

General and administrative expenses were $43.5 million in 2013, an increase of $13.2 million. The increase in general and administrative expenses was primarily due to growth in employees as a result of acquisitions and drilling activities. General and administrative expenses for 2013 included $3.6 million of non-cash unit-based compensation expense and $6.7 million of acquisition-related costs. General and administrative expenses for 2012 were $30.3 million and included $1.4 million of non-cash unit-based compensation expense and $4.1 million of acquisition-related costs.

Net gains on commodity derivative instruments of $26.3 million were recognized during 2013, of which $19.9 million consisted of cash settlements. Net gains on commodity derivative instruments of $21.4 million were recognized during 2012, of which $44.1 million consisted of cash settlements. The decrease in cash settlements was primarily due to higher natural gas prices.

During 2013, a gain of approximately $2.8 million was recorded due to the sale of certain non-operated properties in East Texas. During 2012, a gain of approximately $9.8 million was recognized related to the sale of properties in Garza and Ector Counties in Texas.

Net interest expense during 2013 was $41.9 million, including amortization of deferred financing fees of approximately $5.8 million and gains on interest rate swaps of $1.5 million. Net interest expense during 2012 was $20.4 million, including amortization of deferred financing fees of approximately $0.6 million and losses on interest rate swaps of $4.0 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2013 compared to 2012.

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

A net loss of $45.0 million was generated for the nine months ended September 30, 2014, primarily due to impairment charges, as discussed below, and losses on commodity derivatives. Net income of $9.4 million was generated for the nine months ended September 30, 2013.

Oil, natural gas and NGL revenues for 2014 totaled $368.4 million, an increase of $118.5 million compared with 2013. Production increased 11.1Bcfe (approximately 27%), primarily from drilling activities and increased volumes from third party acquisitions. The average realized sales price increased $0.98 per Mcfe primarily due to higher gas prices and an increase in oil volumes relative to other commodities due to MEMP s acquisitions. The favorable volume and pricing variance contributed to an approximate $67.7 million and $50.8 million increase in revenues, respectively.

Lease operating expenses were $93.4 million and $64.9 million for the nine months ended September 30, 2014 and 2013, respectively. On a per Mcfe basis, lease operating expenses increased to $1.80 for 2014 from $1.59 for 2013. During 2014, MEMP recorded $2.9 million of estimated environmental remediation expenses associated with its Permian and Wyoming oil and gas properties.

Production and ad valorem taxes for 2014 totaled $23.1 million, an increase of $8.2 million compared with 2013 primarily due to an increase in production volumes. On a per Mcfe basis, production and ad

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valorem taxes increased to $0.45 for 2014 from $0.36 for 2013 due to higher production tax rates on a per Mcfe basis for MEMP s Wyoming acquisition.

DD&A expense for 2014 was $105.8 million compared to $69.7 million for 2013, a $36.1 million increase primarily due to both an increase in the depletable cost base and increased production volumes related to third party acquisitions and MEMP s drilling program. Increased production volumes caused DD&A expense to increase by an approximate $18.9 million and the change in the DD&A rate between periods caused DD&A expense to increase by an approximate $17.2 million.

MEMP recognized $67.2 million of impairments in 2014 related primarily to certain properties in South Texas. The estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on pricing terms specified to these properties and increased operating costs. During 2013, the MEMP Segment recorded impairments of $50.3 million. The impairments related to certain properties located in East Texas. The estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on updated well performance data.

General and administrative expenses for 2014 were $31.8 million and included $5.4 million of non-cash unit-based compensation expense and $3.9 million of acquisition-related costs. General and administrative expenses for 2013 totaled $33.4 million and included $2.3 million of non-cash unit-based compensation expense and $3.4 million of acquisition-related costs. The $1.6 million decrease in general administrative expenses included a $5.8 million buyout of Tanos management during 2013 offset by increased salaries and employee count between periods.

Net losses on commodity derivative instruments of $28.7 million were recognized during 2014, consisting of $15.0 million of cash settlement payouts in addition to a $13.7 million decline in the fair value of open hedge positions. Net gains on commodity derivative instruments of $21.2 million were recognized during 2013, consisting of $14.1 million of cash settlement receipts, in addition to a $7.1 million increase in the fair value of open hedge positions.

Net interest expense is comprised of interest on credit facilities, interest on MEMP s outstanding senior notes, amortization of debt issue costs, accretion of net discount associated with the senior notes, and gains and losses on interest rate swaps. Net interest expense totaled $60.6 million during 2014, including losses on interest rate swaps of approximately $0.9 million, amortization of deferred financing fees of approximately $2.9 million, and accretion of net discount associated with the senior notes of $1.3 million. Net interest expense totaled $26.0 million during 2013, including gains on interest rate swaps of $0.2 million and amortization of deferred financing fees of approximately $4.5 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2014 compared to 2013, including MEMP s 2022 Senior Notes.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, the MRD and MEMP Segments operate with independent capital structures. With the exception of cash distributions paid to the MRD Segment by the MEMP Segment related to MEMP partnership interests held by MRD LLC, the cash needs of each segment have been met independently with a combination of operating cash flows, asset sales, credit facility borrowings and the issuance of equity. We expect that the cash needs of each of the MRD Segment and the MEMP Segment will continue to be met independently of each other with a combination of these funding sources.

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MRD Segment

Historically, the primary sources of liquidity have been through borrowings under credit facilities, capital contributions from NGP and certain members of management, borrowings under a second lien term loan facility, issuance of senior notes, asset sales, including dropdowns to MEMP, and net cash provided by operating activities. The primary use of cash has been for the exploitation, development and acquisition of natural gas, NGLs and oil properties. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet future financial obligations, planned capital expenditure activities and liquidity requirements. The future success in growing proved reserves and production will be highly dependent on the capital resources available. As of December 31, 2013, we had 1,582 identified gross potential horizontal well locations, which will take many years to develop. Additionally, the proved undeveloped reserves will require an estimated $1.3 billion of development capital over the next five years according to our reserve report as of December 31, 2013. A significant portion of this capital requirement will be funded out of operating cash flows. However, we may be required to generate or raise significant capital to conduct drilling activities on these identified potential well locations and to finance the development of proved undeveloped reserves.

Currently, the primary sources of liquidity and capital resources are cash flows generated by operating activities and borrowings under our revolving credit facility. We also have the ability to issue additional equity and debt as needed through both private or public offerings. We may from time-to-time refinance our existing indebtedness including by issuing longer-term fixed rate debt to refinance shorter-term floating rate debt.

We believe our cash flows provided by operating activities and availability under our revolving credit facility will provide us with the financial flexibility and wherewithal to meet our cash requirements, including normal operating needs, and pursue our currently planned 2014 development drilling activities. However, future cash flows are subject to a number of variables, including the level of natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties and acquire additional properties. We cannot assure you that operations and other needed capital will be available on acceptable terms, or at all.

As of September 30, 2014, our liquidity of $650.2 million consisted of $9.7 million of cash and cash equivalents and $640.5 million of available borrowings under our revolving credit facility. As of September 30, 2014, we had a working capital deficit balance of $17.8 million primarily due to the timing of accruals, which included accrued capital expenditures of $33.8 million offset by a net asset balance of $15.2 million of current derivative instruments.

Capital Budget

During 2013, we invested approximately $190 million of capital at the MRD Segment to drill 31 gross (21.3 net) wells. A substantial portion of our development program is focused on horizontal drilling of liquids rich wells in the Terryville Complex, where we spent approximately $163 million in capital expenditures to drill 15 gross (12.1 net) horizontal wells during 2013.

In 2014, we have budgeted a total of $351 million to drill and complete 39 gross (34 net) operated wells, which includes $268.7 million of capital expenditures related to drilling recompletions and capital workovers we made during the nine months ended September 30, 2014 (approximately 84% of which were made in the Terryville Complex, 8% of which were made in East Texas, and 8% of which were made in the Rockies). We expect to fund our 2014 development primarily from cash flows from operations. The majority of our drilling locations and our 2014 development program are focused on the Terryville Complex, where we plan to invest $304 million on drilling and completing 33 gross (29 net) horizontal wells and 3 gross (2.7 net) vertical wells. In the Terryville Complex, we plan to run six rigs for the remainder of 2014 targeting primarily our four primary zones within the Cotton Valley the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. Total vertical depth of these zones ranges from 8,200 to 11,200 feet.

In our East Texas properties in the Joaquin Field, we plan to spend development capital of $29 million to drill 4 gross (4 net) horizontal wells targeting the Cotton Valley formation at vertical depths of 6,000 to 10,000 feet.

In our Rockies properties, we plan to spend $18 million of development capital, primarily in the Tepee Field in the Piceance Basin in Colorado focused on 2 gross (2 net) vertical wells.

Cash Flows from Operating, Investing and Financing Activities

The following tables summarize segment cash flows from operating, investing and financing activities for the periods indicated. For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated and Combined Cash Flows included elsewhere in this prospectus.

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MRD Segment

	For Year Ended December 31, 2013	For Year Ended December 31, 2012	For Nine Months Ended September 30, 2014	For Nine Months Ended September 30, 2013
	(unaudited)		(unaudited)	
Net cash provided by operating activities	$ 83,910	$ 84,172	$ 181,683	$ 90,118
Net cash provided by (used in) investing activities				
Acquisition of oil and natural gas properties	$ (67,098)	$ (83,055)	$	$ (67,098)
Additions to oil and gas properties	(198,340)	(165,203)	(267,848)	(130,064)
Additions to other property and equipment	(2,432)	(1,267)	(9,134)	(1,058)
Equity investments in MEMP Segment	(521)	(206)	(570)	(189)
Distributions received from MEMP Segment related to partnership interests	26,006	19,263	6,068	19,100
Decrease (increase) in restricted cash	(49,347)		49,946	
Proceeds from the sale of oil and gas properties to third parties	151,187		6,700	152,274
Proceeds from the sale of MEMP common units	135,012			
Other		(3)	(301)	653
Net cash provided by (used in) investing activities	$ (5,533)	$ (230,471)	$ (215,140)	$ (26,382)
Net cash provided by (used in) financing activities:				
Advances on revolving credit facilities	$ 174,400	$ 228,450	$ 1,139,800	$ 161,700
Payments on revolving credit facilities	(280,500)	(129,750)	(1,314,900)	(200,500)
Proceeds from issuance of senior notes			600,000	
Borrowings under second lien credit facility	325,000			325,000
Redemption of second lien credit facility			(328,282)	
Redemption of senior notes			(351,808)	
Deferred financing costs			(18,875)	(12,619)
Proceeds from the issuance of PIK notes	343,000			
Loan origination fees	(20,267)	(1,276)		
Purchase of noncontrolling interests in consolidated subsidiaries	(13,865)		(3,292)	
Proceeds from initial public offering			408,500	
Costs incurred in conjunction with initial public offering			(28,198)	
Contribution from NGP affiliates related to sale of properties			1,165	
Contribution from NGP affiliate		7,033		
Contributions from MEMP Segment	180,260	29,280	33,880	84,020
Distributions to noncontrolling interest	(7,446)		(325)	(7,531)
Distributions to MEMP Segment		(1,900)		
Distributions to NGP affiliates				
Distributions to Funds	(732,362)			(363,437)
Distributions to MRD Holdco			(59,803)	
Distribution to NGP affiliates related to purchase of assets			(66,693)	
Distribution to NGP affiliate related to sale of assets, net of cash received			(32,770)	
Distributions made by previous owners	(2,590)	(2,317)		(1,715)
Other cash transfers from MEMP Segment		3,751		
Other	(4,593)		213	(6,296)
Net cash provided by (used in) financing activities	$ (38,963)	$ 133,271	$ (21,388)	$ (21,378)

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Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

Operating Activities. Net cash flows provided by operating activities were $83.9 million in 2013 compared to $84.2 million in 2012. Although production volumes increased 15,088 MMcfe (approximately 48%), net cash flows from operating activities were impacted by $43.3 million of compensation expense recognized in 2013 related to incentive unit payments, which was an increase of $33.8 million from 2012.

Investing Activities. Cash used in investing activities was $5.5 million during 2013 compared to $230.5 million in 2012. Cash used for the acquisition of oil and gas properties was $67.1 million in 2013 compared to $83.1 million in 2012. The 2013 acquisition was for certain properties located in Louisiana that were purchased in March 2013. The 2012 acquisitions consisted primarily of properties located in East Texas and North Louisiana.

Cash used for additions to oil and gas properties was $198.3 million in 2013 compared to $165.2 million in 2012. The additions in both 2013 and 2012 consisted primarily of drilling and completion activities focused on the Cotton Valley formation in North Louisiana and East Texas.

Distributions of $26.0 million were received in 2013 from MEMP related to the common and subordinated units owned by MRD LLC as compared to $19.3 million received in 2012. In November 2013, MRD LLC sold 7,061,294 MEMP common units in a public offering, which generated net proceeds of $135.0 million.

Proceeds from the sale of oil and gas properties totaled $151.2 million in 2013. In May 2013, Black Diamond sold certain of its Wyoming properties for approximately $33.0 million. In July 2013, BlueStone sold its interest in certain properties located in Walker and Madison Counties in East Texas for approximately $117.9 million. There were no sales of oil and gas properties in 2012.

Additions to restricted cash totaled $49.3 million and were primarily related to the $50.0 million debt service reserve established in connection with the issuance of the PIK notes in December 2013.

Financing Activities. Cash used in financing activities was $39.0 million in 2013 compared to cash provided by financing activities of $133.3 million in 2012. Net payments under revolving credit facilities were $106.1 million in 2013 compared to net borrowings of $98.7 million in 2012. In June 2013, WildHorse Resources received gross proceeds of $325.0 million under its second lien term loan and in December 2013, MRD LLC received gross proceeds of $343.0 million related to the issuance of the PIK notes. Deferred financing costs were $20.3 million in 2013 compared to $1.3 million in 2012. The increase in deferred financing costs was primarily due to the WildHorse second lien term loan and the PIK notes.

In November 2013, MRD LLC purchased the noncontrolling interests in Black Diamond, Classic GP and Classic for $13.9 million of consideration.

Cash received from the MEMP Segment in 2013 related to the sale of assets from the MRD Segment to the MEMP Segment was $180.3 million compared to $29.3 million.

Distributions to the Funds during 2013 were $732.4 million. From time to time, MRD LLC has made distributions of cash to the Funds. The timing and amount of these cash distributions is within the discretion of the board of managers of MRD LLC and is based, in part, upon available cash, the performance of its business, and other relevant factors. In 2013, substantially all of the cash distributed to the Funds was sourced from long term borrowings or sales of assets or equity in MEMP. The sources to fund these distributions primarily included $225.0 million from the WildHorse second lien term loan, $210.0 million from the December 2013 PIK notes, $63.8 million from the sale of properties to third parties, $125.0 million from the sale of properties to MEMP and $105.0 million from the sale of 7,061,294 MEMP common units that MRD LLC owned. Distributions to noncontrolling interests and previous owners totaled $15.9 million in 2013 compared to $2.3 million in 2012.

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Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

Operating Activities. Net cash flows provided by operating activities were $181.7 million during 2014 compared to $90.1 million during 2013. Production increased 22.8 Bcfe (approximately 67%) and average realized sales price increased $0.27 per Mcfe as previously discussed under Results of Operations MRD Segment. Cash paid for interest during 2014 was $35.5 million compared to $12.8 million during 2013. During 2014, compensation expense of approximately $26.7 million was paid in cash related to WildHorse Resources incentive units compared to $19.1 million in 2013 related to BlueStone units.

Investing Activities. Total cash used in investing activities was $215.1 million during 2014 compared to $26.4 million for the same period in 2013. Cash used for additions to oil and gas properties $267.8 million during 2014 compared to $130.1 million for the same period in 2013, which consisted primarily of drilling and completion activities in the Cotton Valley in North Louisiana and East Texas area. Additions to other property and equipment were $9.1 million which consisted primarily of computer hardware, software, and other leased office space build out during 2014. On April 30, 2013, WildHorse Resources purchased certain oil and gas properties and leases in Louisiana from a third party for approximately $67.1 million. Distributions of $6.1 million were received from MEMP primarily from the subordinated units owned by MRD LLC during 2014 compared to $19.1 million during 2013 received from MEMP primarily from the common and subordinated units owned by MRD LLC. On May 9, 2014, Black Diamond sold certain producing and non-producing properties in the Mississippian oil play of Northern Oklahoma to a third party for cash consideration of approximately $6.7 million, subject to customary post-closing adjustments. On July 31, 2013, BlueStone entered into an agreement with a third party to sell its remaining interest in certain properties in the Mossy Grove Prospect in Walker and Madison Counties located in East Texas. Total cash consideration received by BlueStone was approximately $117.9 million. On June 4, 2013, Black Diamond sold certain of its Wyoming oil and gas properties to a third party for cash consideration of approximately $32.9 million. There was a decrease in restricted cash of $49.9 million, which was primarily due to $50.0 million being released from the debt service reserve account associated with the PIK notes.

Financing Activities. On June 18, 2014, we completed our initial public offering pursuant to which we sold 21,500,000 shares of our common stock to the public at an offering price of $19.00 per share. Net proceeds from our initial public offering were $380.3 million. We used approximately $360.0 million of our initial public offering proceeds to redeem the PIK notes on June 27, 2014, of which $351.8 million was classified as a financing activity and the remaining $8.2 million was classified as an operating activity representing interest expense.

Net repayments under revolving credit facilities were $175.1 million during 2014 compared to net repayments of $38.8 million during 2013. Amounts borrowed under our revolving credit facility were primarily incurred to repay the amounts outstanding under WildHorse Resources credit facilities in connection with the closing of our initial public offering. WildHorse Resources primarily utilized its revolving credit facility during 2014 to repurchase net profits interests from an affiliate of NGP. On June 13, 2013, WildHorse Resources borrowed $325.0 million under its second lien term loan agreement and used such borrowings to reduce outstanding indebtedness under its revolving credit facility and to pay a onetime special $225.0 million distribution to MRD LLC, which MRD LLC subsequently distributed to the Funds. In connection with the closing of our initial public offering, WildHorse Resources second lien term loan was repaid in full, including a premium of approximately $3.3 million.

Net proceeds of $584.9 million from the issuance of our MRD Senior Notes during the nine months ending September 30, 2014 were used to repay portions of our borrowings outstanding under our revolving credit facility.

Distributions to NGP affiliates related to the purchase of assets were primarily related to WildHorse Resources February 2014 acquisition of net profits interests in the Terryville Complex from an affiliate of NGP for $63.4 million. MRD Royalty also acquired certain interests in oil and gas properties in Gonzales and Karnes Counties located in South Texas from an affiliate of NGP for $3.3 million in March 2014.

Distributions to NGP affiliates related to the sale of assets were $32.8 million. WildHorse Resources sold its subsidiary, WHR Management Company, to an affiliate of the Funds for approximately $0.2 million and

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$33.0 million of cash was a component of the net book value transferred. For additional information regarding this transaction, see Note 13 of the Notes to Unaudited Condensed Consolidated and Combined Financial Statements included under Item 1 of this quarterly report.

MEMP paid $33.9 million to WildHorse Resources in connection with MEMP s April 1, 2014 acquisition of certain oil and natural gas properties in East Texas. MEMP paid $55.4 million to WildHorse Resources in connection with MEMP s March 28, 2013 acquisition of all the outstanding equity interests in WHT. Tanos also distributed approximately $28.6 million to MRD LLC during 2013.

In connection with the our initial public offering, certain former management members of WildHorse Resources contributed their 0.1% membership interest in WildHorse Resources as well as their incentive units in exchange for 42,334,323 shares of our common stock and cash consideration of $30.0 million. The portion of the total consideration related to acquiring the 0.1% membership interest was $3.3 million.

Distributions to MRD Holdco during 2014 were $59.8 million. Approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy s assets in May 2014 was distributed to MRD Holdco in connection with our initial public offering. We also reimbursed MRD LLC for the approximately $17.2 million interest payment that it made on the PIK notes on June 15, 2014, which was distributed to MRD Holdco. Remaining cash of $32.8 million released from the debt service reserve account in connection with the redemption and discharge of the PIK notes was also distributed to MRD Holdco.

Distributions to the Funds during 2013 were $363.4 million. From time-to-time, MRD LLC made distributions of cash to the Funds. The timing and amount of these cash distributions was within the discretion of the board of managers of MRD LLC and was based, in part, upon available cash, the performance of its business, and other relevant factors. During 2013, substantially all of the cash distributed to the Funds was sourced from long term borrowings or sales of assets. The sources to fund these distributions primarily included $225.0 million from the WildHorse second lien term loan, $75.0 million from the sale of properties to MEMP, and approximately $63.4 million related to the sale of properties by BlueStone.

Deferred financing costs of approximately $18.9 million were incurred during 2014 compared to approximately $12.6 million during 2013.

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MEMP Segment

	For Year Ended December 31, 2013	For Year Ended December 31, 2012	For Nine Months Ended September 30, 2014	For Nine Months Ended September 30, 2013
	(unaudited)		(unaudited)	
Net cash provided by operating activities	$ 193,697	$ 156,844	$ 183,777	$ 147,005
Net cash provided by (used in) investing activities:				
Acquisition of oil and natural gas properties	$ (38,664)	$ (277,623)	$ (1,083,167)	$ (37,828)
Additions to oil and gas properties	(161,675)	(107,789)	(189,990)	(127,449)
Additions to other property and equipment	(238)	(1,748)		(126)
Additions to restricted investments	(5,361)	(4,599)	(2,883)	(4,263)
Proceeds from the sale of oil and gas properties	4,525	34,521		4,525
Deposits for property acquisitions				(25,310)
Other		29		
Net cash provided by (used in) investing activities	$ (201,413)	$ (357,209)	$ (1,276,040)	$ (190,451)
Net cash provided by (used in) financing activities:				
Advances on revolving credit facilities	$ 958,355	$ 391,000	$ 1,325,000	$ 316,355
Payments on revolving credit facilities	(1,485,537)	(121,819)	(1,127,000)	(699,868)
Proceeds from the issuance of senior notes	688,563		492,425	397,563
Deferred financing costs	(20,908)	(2,225)	(11,409)	(11,218)
Contributions from previous owners	7,233	44,072		7,233
Contribution from NGP affiliate	2,013	38,125		2,013
Contribution from general partner	521	206	570	189
Contributions from MRD Segment		1,900		
Net proceeds from public equity offering	490,138	194,304	541,066	171,779
Distributions to partners	(96,643)	(34,436)	(107,070)	(62,888)
Distributions to MRD Segment	(180,260)	(29,280)	(33,880)	(84,020)
Distributions to NGP affiliates	(355,495)	(242,174)		
Distributions made by previous owners	(2,552)	(26,455)		(2,552)
Other cash transfers to MRD Segment		(3,751)		
Other	(9,013)	(646)		55
Net cash provided by (used in) financing activities	$ (3,585)	$ 208,821	$ 1,079,702	$ 34,641

Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

Operating Activities. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs. Net cash flows provided by operating activities increased during 2013 primarily due to an increase in production volumes as a result of acquisitions and increased drilling activities. Cash flows provided by operating activities at the MEMP Segment are used primarily to fund distributions to its partners and additions to oil and gas properties. The previous owners primarily used cash flows provided by operating activities to fund its exploration and development expenditures.

Investing Activities. Cash used in investing activities during 2013 was $201.4 million, of which $38.7 million was used to acquire oil and gas properties located in Wyoming and East Texas and $161.7 million was used for additions to oil and gas properties. Cash used in investing activities during 2012 was $357.2 million, of which $277.6 million was used to acquire oil and gas properties and $107.8 million was used for additions to oil and gas properties. The 2012 acquisitions included $126.9 million of acquisitions in East Texas and $150.7 million of acquisitions in the Permian Basin.

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Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Southern California oil properties. For the years ended December 31, 2013 and 2012, additions to restricted investments were $5.4 million and $4.6 million, respectively.

Proceeds from the sale of oil and gas properties were $4.5 million in 2013 compared to $34.5 million in 2012. The 2013 sales primarily consisted of certain non-operated properties in East Texas while the 2012 sales primarily consisted of certain properties in Garza and Ector counties located in West Texas.

Financing Activities. Cash used in financing activities was $3.6 million in 2013 compared to cash provided by financing activities of $208.8 million in 2012.

MEMP generated total net proceeds of $490.1 million from two separate equity offerings in 2013 compared to $194.3 million in 2012. In March 2013, MEMP issued 9,775,000 common units to the public at an offering price of $18.35 per unit generating net proceeds of approximately $171.8 million. In October 2013, MEMP issued 16,675,000 common units to the public at an offering price of $19.90 per unit generating net proceeds of approximately $318.3 million. In December 2012, MEMP generated net proceeds of $194.3 million from a public offering of common units.

MEMP completed a private placement of 7.625% senior notes due 2021 (the Senior Notes) with two additional issuances during 2013. MEMP issued $300.0 million aggregate principal amount of the Senior Notes at 98.521% of par in April 2013, an additional $100.0 million aggregate principal amount at 102.0% of par in May 2013 and an additional $300.0 million aggregate principal amount at 97.0% of par in October 2013. Total proceeds, net of discounts, from the issuance of the Senior Notes were $688.6 million during 2013.

Distributions to partners were $96.6 million during the year ended December 31, 2013 compared to $34.4 million during the year ended December 31, 2012 due to increases in both declared distribution rates per unit and increases in the number of outstanding units. Distributions to the MRD Segment totaled $180.3 million in 2013 compared to $29.3 million in 2012. These distributions were primarily associated with the acquisition of assets by MEMP from the MRD Segment. Distributions to NGP affiliates were $355.5 million in 2013 compared to $242.2 million in 2012. The 2013 distribution was associated with the acquisition of assets by MEMP from certain affiliates of NGP in October 2013. The 2012 distribution was associated with the acquisition of assets located offshore Southern California from an affiliate of NGP.

The previous owners received contributions of $7.2 million during 2013 compared to $44.1 million during 2012. Distributions made by the previous owners totaled $2.6 million in 2013 compared to $26.5 million in 2012.

MEMP had net payments of $527.2 million during 2013 related to revolving credit facilities. Borrowings under revolving credit facilities were used primarily to fund distributions associated with acquisitions of oil and gas properties from affiliates of NGP. Proceeds from the issuance of the Senior Notes and common unit public equity offerings were used to repay borrowings under MEMP s revolving credit facility. During 2012, MEMP had net borrowings of $269.2 million related to revolving credit facilities. These borrowings were primarily used to fund distributions associated with acquisitions of oil and gas properties from affiliates of NGP. Deferred financing costs of $20.9 million were incurred during 2013 associated with both the Senior Notes and MEMP s revolving credit facility compared to $2.2 million incurred in 2012 related to revolving credit facilities.

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

Operating Activities. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs. Net income decreased by $54.4 million as further discussed above under Results of Operations MEMP Segment, and net cash provided by operating activities increased by $36.8 million. Cash paid for interest during 2014 was $32.0 million compared to $10.1 million during 2013. Net cash provided by operating activities included $11.4 million period-to-period increase in cash flow attributable to the timing of cash receipts and disbursements related to operating activities during 2014 compared to 2013.

Investing Activities. Net cash used in investing activities during 2014 was $1.28 billion, of which $1.08 billion was used to acquire oil and natural gas properties from a third parties and $190.0 million was used for additions to oil and gas properties. Cash used in investing activities during 2013 was $190.4 million, of which $37.8 million was used to acquire oil and natural gas properties from a third parties and $127.4 million was used for additions to oil and gas properties. During the nine months ended September 30, 2013, we paid a deposit of $25.3 million related to the Cinco Acquisition. During the nine months ended September 30, 2013, Tanos had sales proceeds of $4.5 million related to the sale of oil and natural gas properties. Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with MEMP s offshore Southern California oil and gas properties.

Financing Activities. For the nine months ended September 30, 2014, MEMP issued a total of 24,840,000 common units generating gross proceeds of approximately $553.3 million offset by approximately $12.2 million of costs incurred in conjunction with the issuance of common units. The net proceeds from these issuances were primarily used to repay borrowings on MEMP s revolving credit facility. On March 25, 2013, MEMP issued 9,775,000 common units representing limited partner interests in the Partnership to the public at an offering price of $18.35 per unit generating gross proceeds of approximately $179.4 million, offset by approximately $7.6 million of costs incurred in conjunction with the issuance of common units. The net proceeds from this equity offering, including MEMP GP s proportionate capital contribution, partially funded the acquisition of all of the outstanding equity interests in WHT.

Distributions to partners during 2014 were $107.1 million compared to $62.9 million during 2013, of which the MRD Segment received $6.1 million during 2014 compared to $19.1 million during 2013. The increase in total distributions is due to both an increase in MEMP s outstanding units between periods and an increase in the declared cash distribution rate per unit. The decrease in distributions to the MRD Segment is due to MRD LLC selling 7,061,294 common units in November 2013 and distributed 5,360,912 subordinated units to MRD Holdco in June 2014 in connection with our initial public offering.

MEMP paid $33.9 million to WildHorse Resources in connection with MEMP s April 1, 2014 acquisition of certain oil and natural gas properties in East Texas. MEMP paid $55.4 million to WildHorse Resources in connection with its March 28, 2013 acquisition of all of the outstanding equity interests in WHT and repaid $89.3 million of indebtedness under WHT s credit facility. Tanos also distributed approximately $28.6 million to MRD LLC during 2013.

MEMP s previous owners received contributions of $7.2 million during 2013, of which Tanos received $5.2 million from MRD LLC. Distributions made by MEMP s previous owners totaled $2.6 million in 2013.

MEMP had net payments of $276.0 million under its revolving credit facility during 2013. The Cinco Group had advances of $18.4 million under their credit facilities and repaid $36.6 million of outstanding borrowings during the nine months ending September 30, 2013. MEMP had borrowings of $1.33 billion under its revolving credit facility during 2014 that were used primarily to fund their acquisitions and drilling program. Deferred financing costs of approximately $11.4 million were incurred during 2014 compared to approximately $11.2 million during 2013.

Proceeds of $492.4 million from the issuances of the 2022 Senior Notes during 2014 were used to repay borrowings outstanding under MEMP s revolving credit facility.

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Debt Agreements MRD Segment

Revolving Credit Facility

On June 18, 2014, we, as borrower, and certain of our subsidiaries, as guarantors, entered into a revolving credit facility, which is a five-year, $2.0 billion revolving credit facility with an initial borrowing base of $725 million and aggregate elected commitments of $725 million. On October 3, 2014, the borrowing base and aggregate elected commitments was increased from $668.5 million to $725 million.

We are permitted to borrow under the revolving credit facility in an amount up to the least of (i) the face amount of our revolving credit facility, (ii) the borrowing base and (iii) the aggregate elected commitments. The revolving credit facility is reserve-based, and thus our borrowing base is primarily based on the estimated value of our oil, NGL and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. Our borrowing base is subject to redetermination on a semi-annual basis based on an engineering report with respect to our estimated oil, NGL and natural gas reserves, which will take into account the prevailing oil, NGL and natural gas prices at such time, as adjusted for the impact of our commodity derivative contracts. Unanimous approval by the lenders is required for any increase to the borrowing base. In addition, we may, subject to certain conditions, increase our aggregate elected commitments in an amount not to exceed the then effective borrowing base on or following a scheduled redetermination of our borrowing base once before the next scheduled redetermination date. In the future, we may be unable to access sufficient capital under the revolving credit facility as a result of (i) a decrease in our borrowing base due to a subsequent borrowing base redetermination or (ii) an unwillingness or inability on the part of our lenders to meet their funding obligations.

A future decline in commodity prices could result in a redetermination that lowers our borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base, or we could be required to pledge other oil and natural gas properties as additional collateral. If a redetermination of our borrowing base results in our borrowing base being less than our aggregate elected commitments, our aggregate elected commitments will be automatically reduced to the amount of such reduced borrowing base. We do not anticipate having any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility.

Borrowings under the revolving credit facility are secured by liens on substantially all of our properties, but in any event, not less than 80% of the total value of our oil and natural gas properties, and all of our equity interests in any future guarantor subsidiaries and all of our other assets including personal property. Additionally, borrowings bear interest, at our option, at either (i) the greatest of (x) the prime rate as determined by the administrative agent, (y) the federal funds effective rate plus 0.50%, and (z) the one-month adjusted LIBOR plus 1.0% (adjusted upwards, if necessary, to the next 1/100th of 1%), in each case, plus a margin that varies from 0.50% to 1.50% per annum according to the total commitment usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 1.50% to 2.50% per annum according to the total commitment usage. The unused portion of the total commitments is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to our total commitments usage.

The revolving credit facility requires maintenance of a ratio of Consolidated EBITDAX to Consolidated Net Interest Expense (as each term is determined under the revolving credit facility), which we refer to as the interest coverage ratio, of not less than 2.5 to 1.0, and a ratio of consolidated current assets to consolidated current liabilities, each as determined under the revolving credit facility, which we refer to as the current ratio, of not less than 1.0 to 1.0.

Additionally, the revolving credit facility contains various covenants and restrictive provisions that, among other things, limit our ability to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of our assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of our production and prepay certain indebtedness.

Events of default under the revolving credit facility include, but are not limited to, failure to make payments when due, breach of any covenant continuing beyond the applicable cure period, default under any other material debt, change in management or change of control, bankruptcy or other insolvency event and certain material adverse effects on our business.

If we fail to perform our obligations under these and other covenants, the revolving credit commitments could be terminated and any outstanding indebtedness together with accrued interest, fees and other obligations under the revolving credit facility, could be declared immediately due and payable.

MRD Senior Notes

The MRD Senior Notes will mature on July 1, 2022. Interest on the MRD Senior Notes will accrue from July 10, 2014 and will be payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2015. The MRD Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of our existing subsidiaries. The MRD Senior Notes and the guarantees of the MRD Senior Notes will rank equally with our and the guarantors existing and future senior indebtedness, will be effectively junior to all of our and the guarantors existing and future secured indebtedness (to the extent of the value of the assets securing such indebtedness), and senior in right of payment to all of our and the guarantors subordinated indebtedness. The MRD Senior Notes will be structurally subordinated to the indebtedness and other liabilities of our non-guarantor subsidiaries, including MEMP and its subsidiaries and MEMP GP.

The MRD Senior Notes are governed by an indenture dated as of July 10, 2014. The MRD Senior Notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any, to the date of redemption. The Company may also be required to repurchase the MRD Senior Notes upon a change of control. The indenture contains customary covenants and restrictive provisions, many of which will terminate if at any time no default exists under the indenture and the MRD Senior Notes receive an investment grade rating from both of two specified ratings agencies. MEMP and its subsidiaries are not subject to these covenants. The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to either the Company or the guarantors, all outstanding MRD Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding MRD Senior Notes may declare all the MRD Senior Notes to be due and payable immediately.

MRD LLC Revolving Credit Agreement (Terminated)

On July 13, 2012, MRD LLC entered into a two-year $50.0 million senior secured revolving credit facility with an initial borrowing base of $35.0 million. MRD LLC pledged 7,061,294 MEMP common units and 5,360,912 MEMP subordinated units as security under the credit facility as well as its oil and gas properties and certain other assets of MRD LLC. On November 20, 2012, MRD LLC entered into a first amendment to its credit agreement, which among other things: (i) increased the aggregate maximum credit to $1.0 billion (ii) increased the borrowing base to $120.0 million and (iii) extended the maturity date to November 20, 2016. On April 25, 2013, MRD LLC entered into a second amendment to its credit agreement, which among other things: (i) increased the borrowing base to $170.0 million and (ii) designated Tanos together with its consolidating subsidiaries as additional guarantors.

On October 1, 2013, Tanos and its consolidating subsidiaries were removed as guarantors and the borrowing base was reduced to $120.0 million. On November 1, 2013, MRD LLC entered into a third amendment to its credit agreement, which among other things: (i) designated Black Diamond together with its consolidating subsidiaries as additional guarantors, (ii) reduced the borrowing base to $100.0 million, and (iii) permitted second lien indebtedness. On November 22, 2013, the borrowing base was automatically reduced to $60.0 million upon MRD LLC s sale of 7,061,294 MEMP common units in a secondary offering. On December 18, 2013, indebtedness then outstanding under the revolving credit facility of $59.7 million and all accrued interest were paid off in full and the revolving credit facility was terminated in connection with the issuance of the PIK notes discussed below.

PIK Notes (Redeemed)

A redemption notice was delivered to the PIK notes trustee on June 16, 2014, which specified a redemption date of July 16, 2014 at a redemption price of 102% of the principal amount of the PIK notes plus accrued and unpaid interest thereon to the date of redemption. In connection with the closing of our initial public offering, we assumed the obligations of MRD LLC under the PIK notes indenture and the related debt security agreement. We irrevocably deposited with the PIK notes trustee approximately $360.0 million on June 27, 2014, which was an amount sufficient to fund the redemption of the PIK notes on the redemption date and to satisfy and discharge our obligations under the PIK notes and the related indenture. The discharge became effective upon the irrevocable deposit of the funds with the PIK notes trustee.

WildHorse Resources Revolving Credit Facility and Second Lien Facility (Terminated)

In connection with the closing of our initial public offering, the WildHorse Resources revolving credit facility and second lien term loan were repaid in full and terminated.

Black Diamond Revolving Credit Facility (Terminated)

On July 27, 2011, the Black Diamond entered into a second amended and restated revolving credit facility, which extended the maturity date of the original agreement to May 9, 2015. Borrowings under the revolving credit facility are collateralized by Black Diamond s oil and natural gas properties. On November 1, 2013, the Black Diamond revolving credit facility was terminated. There was no indebtedness outstanding or accrued interest payable on such date.

Debt Agreements MEMP Segment

MEMP Revolving Credit Facility

On December 14, 2011, Memorial Production Operating LLC (OLLC), a wholly-owned subsidiary of MEMP, entered into multi-year $1.0 billion senior secured revolving credit facility with an initial borrowing base of $300.0 million. A sixth amendment to the credit agreement was entered into on September 26, 2013, which among other things: (i) increased the facility from $1.0 billion to $2.0 billion and (ii) increased the borrowing base from $480.0 million to $920.0 million upon the closing of MEMP s $603.0 million acquisition that closed October 1, 2013. On October 10, 2013, borrowing base was automatically reduced by $75.0 million in conjunction with the issuance of additional senior notes as discussed below in accordance with the terms of the credit facility. A seventh amendment to the credit agreement was entered into on June 13, 2014, which among other things increased the borrowing base to $1.44 billion upon the closing of the MEMP Wyoming Acquisition. On

July 17, 2014, the borrowing base was automatically reduced by $125.0 million in conjunction with the issuance of the 2022 Senior Notes in accordance with the terms of the credit facility. Borrowings under the revolving credit facility are secured by liens on substantially all of MEMP s properties, but in any event, not less than 80% of the total value of MEMP s oil and natural gas properties, and all of MEMP s equity interests in OLLC and any future guarantor subsidiaries (other than San Pedro Bay Pipeline Company) and all of MEMP s other assets including personal property. Additionally, borrowings under the revolving credit facility bear interest, at MEMP s option, at: (i) the Alternative Base Rate defined as the greatest of (x) the prime rate as determined by the administrative agent, (y) the federal funds effective rate plus 0.50%, and (z) the one-month adjusted LIBOR plus 1.0% (adjusted upwards, if necessary, to the next 1/100th of 1%), in each case, plus a margin that varies from 0.50% to 1.50% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), (ii) the applicable LIBOR plus a margin that varies from 1.50% to 2.50% per annum according to the borrowing base usage, or (iii) the applicable LIBOR Market Index plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. The unused portion of the borrowing base will be subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

2021 Senior Notes

On April 17, 2013, MEMP and Finance Corp. completed a private placement of $300.0 million aggregate principal amount of 7.625% senior unsecured notes due 2021 (the Senior Notes). The Senior Notes were issued at 98.521% of par and are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by all of the MEMP s subsidiaries (other than Finance Corp., which is co-issuer of the Senior Notes, and certain immaterial subsidiaries). On May 23, 2013, the Issuers issued an additional $100.0 million aggregate principal amount of the Senior Notes at 102% of par. The Senior Notes will mature on May 1, 2021 with interest accruing at a rate of 7.625% per annum and payable semi-annually in arrears on May 1 and November 1 of each year, commencing November 1, 2013. The Senior Notes are governed by an indenture. The Senior Notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any. The Issuers may also be required to repurchase the Senior Notes upon a change of control. The indenture contains customary covenants and restrictive provisions, many of which will terminate if at any time no default exists under the indenture and the Senior Notes receive an investment grade rating from both of two specified ratings agencies. The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to either of the Issuers, all outstanding Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding Senior Notes may declare all the Senior Notes to be due and payable immediately.

2022 Senior Notes

On July 17, 2014, the MEMP Issuers issued the 2022 Senior Notes as previously discussed under Significant Recent Developments MEMP Segment.

For additional information regarding the 2022 Senior Notes, see Note 8 of the Notes to Unaudited Condensed Consolidated and Combined Financial Statements included elsewhere in this prospectus.

Previous Owner Revolving Credit Facilities (Terminated)

On October 1, 2013, the debt balance then outstanding under the Boaz and Crown revolving credit facilities and all accrued interest was paid off in full and these revolving credit facilities were terminated. On October 1, 2013, the debt balance then outstanding under the Stanolind and Propel Energy revolving credit facilities and all accrued interest was paid off in full by MEMP on behalf of Stanolind and Propel Energy, respectively.

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Contractual Obligations

In the table below, we set forth MRD LLC s consolidated and combined contractual obligations as of December 31, 2013. The contractual obligations that will actually be paid in future periods may vary from those reflected in the table because the estimates and assumptions are subjective.

During the nine months ended September 30, 2014, there were no significant changes in our consolidated and combined contractual obligations except for borrowings and repayments under revolving credit facilities, the redemption of the PIK notes, the repayment and termination of WildHorse Resources revolving and second lien credit facilities, the issuance of senior notes by both MRD and MEMP, and the assumption of a purchase commitment presented in the table below.

	Payments Due by Period (in thousands)				
Contractual Obligations	Total	2014	2015 - 2016	2017 2018	Beyond 2018
Revolving credit facility(1)					
MRD Segment	$ 203,100	$	$	$ 203,100	$
MEMP Segment	103,000			103,000	
Estimated interest payments(2)					
MRD Segment	20,242	4,671	9,342	6,229	
MEMP Segment	14,227	3,348	6,695	4,184	
Notes and Second Lien Term Loan(3)					
MRD Segment	973,500	59,700	119,400	794,400	
MEMP Segment	1,100,313	53,375	106,750	106,750	833,438
Asset retirement obligations(4)					
MRD Segment	12,150	90	1,818	2,775	7,467
MEMP Segment	99,619		1,878	6,373	91,368
Decommissioning Trust Agreement(5)					
MRD Segment					
MEMP Segment	12,392	2,042	10,350		
Operating leases					
MRD Segment	16,340	1,840	4,153	5,091	5,256
MEMP Segment	3,985	549	976	410	2,050
Compression services					
MRD Segment	583	572	11		
MEMP Segment	6,507	6,507			
Drilling services					
MRD Segment	20,323	20,323			
MEMP Segment					
Processing Plant Demand Fees					
MRD Segment	118,182	19,347	51,606	47,229	
MEMP Segment					
Total	$ 2,704,463	$ 172,364	$ 312,979	$ 1,279,541	$ 939,579

(1) Represents the scheduled future maturities of principal amounts outstanding for the periods indicated. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for information regarding our revolving credit facilities.

(2) Estimated interest payments are based on the principal amount outstanding under revolving credit facilities at December 31, 2013. In calculating these amounts, we applied the weighted-average interest rate during 2013 associated with such debt. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for the weighted-average variable interest rate charged during 2013 under these credit facilities. In addition, the estimate of payments for interest gives effect to interest rate swap agreements that were in place at December 31, 2013.

(3) Represents the scheduled future interest payments and principal payments on the PIK notes, the Senior Notes and the WildHorse Resources second lien term loan. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for information regarding debt agreements.

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(4) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2013 balance sheet. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for additional information regarding our asset retirement obligations.

(5) Pursuant to a Bureau of Ocean Energy Management decommissioning trust agreement, the Partnership is required to fund a trust account to comply with supplemental regulatory bonding requirements related to decommissioning obligations for the offshore Southern California production facilities. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for additional information.

During the nine months ended September 30, 2014, MEMP assumed the following contractual obligation as a result of its Wyoming Acquisition as noted above (in thousands):

		Payment or Settlement due by Period			
Purchase commitment	**Total**	**Remainder 2014**	**2015 -2016**	**2017 -2018**	**Beyond 2018**
CO_2 minimum purchase commitment:					
Estimated payment obligation(1)	$ 62,103	$ 3,203	$ 24,323	$ 19,496	$ 15,081

(1) Represents firm agreement to purchase CO_2 volumes as of September 30, 2014.

Critical Accounting Policies and Estimates

Natural Gas and Oil Properties

We use the successful efforts method of accounting to account for our natural gas and oil properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells, and development costs are capitalized. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete. Exploration costs such as geological, geophysical, and seismic costs are expensed as incurred.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties are subject to depreciation and depletion. Depletion of capitalized costs is provided using the units-of-production method based on proved natural gas and oil reserves related to the associated field. Capitalized drilling and development costs of producing natural gas and oil properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves.

On the sale or retirement of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and any gain or loss is recognized.

Proved Natural Gas and Oil Reserves

The estimates of proved natural gas and oil reserves utilized in the preparation of the consolidated and combined financial statements are estimated in accordance with the rules established by the SEC and the FASB. These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements. We intend to use NSAI to prepare a reserve report as of December 31 of each year for a vast majority of our proved reserves and to prepare internal estimates of our proved reserves as of June 30 of each year.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Oil and gas properties are depleted by field using the units-of-production method. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of natural gas and oil reserves, the remaining estimated lives of natural gas and oil properties, or any combination of the above may be increased or reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

A decline in proved reserves may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of oil and gas producing properties for impairment.

Impairments

Proved natural gas and oil properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates, less than expected production, drilling results, higher operating and development costs, or lower commodity prices. The estimated undiscounted future cash flows expected in connection with the property are compared to the carrying value of the property to determine if the carrying amount is recoverable. If the carrying value of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

Asset Retirement Obligations

An asset retirement obligation associated with retiring long-lived assets is recognized as a liability on a discounted basis in the period in which the legal obligation is incurred and becomes determinable, with an equal amount capitalized as an addition to natural gas and oil properties, which is allocated to expense over the useful life of the asset. Generally, oil and gas producing companies incur such a liability upon acquiring or drilling a well. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. Upon settlement of the liability, a gain or loss is recognized to the extent the actual costs differ from the recorded liability.

Incentive Units

Prior to our initial public offering, the governing documents of MRD LLC and certain of MRD LLC s subsidiaries, including WildHorse Resources and BlueStone, provided for the issuance of incentive units. Those incentive units were subject to performance conditions that affected their vesting. Compensation cost was recognized only if the performance condition was probable of being satisfied at each reporting date.

WildHorse Resources, BlueStone and MRD LLC each granted incentive units to certain of its members who were key employees at the time of grant. Holders of incentive units were entitled to distributions ranging from 10% to 31.5% when declared, but only after cumulative distribution thresholds (payouts) have been achieved. Payouts would have been generally triggered after the recovery of specified members capital contributions plus a rate of return.

Vesting of incentive units is generally dependent upon an explicit service period, a fundamental change as defined in the respective governing document, and achievement of payout. All incentive units not vested are forfeited if an employee is no longer employed. All incentive units will be forfeited if a holder resigns whether the incentive units are vested or not. If the payouts have not yet occurred, then all incentive units, whether or not vested, will be forfeited automatically (unless extended).

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In connection with the closing of our initial public offering, certain former management members of WildHorse Resources contributed to us their incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources in exchange for approximately 42.3 million shares of our common stock and cash consideration of $30.0 million. See Note 12 of the Notes to Unaudited Condensed Consolidate and Combined Financial Statements included elsewhere in this prospectus for additional information.

In connection with the restructuring transactions, the MRD LLC incentive units were exchanged for substantially identical units in MRD Holdco, and such incentive units entitle holders thereof to portions of future distributions by MRD Holdco. While any such distributions made by MRD Holdco will not involve any cash payment by us, we will be required to recognize non-cash compensation expense within general and administrative expenses, which may be material, in the period in which the performance conditions are probable of being satisfied. The compensation expense recognized by us related to the incentive units will be offset by a deemed capital contribution from MRD Holdco. See Note 12 of the Notes to Unaudited Condensed Consolidate and Combined Financial Statements included elsewhere in this prospectus for additional information.

Revenue Recognition

Revenue from the sale of natural gas and oil is recognized when title passes, net of royalties due to third parties. Natural gas and oil revenues are recorded using the sales method. Under this method, revenues are recognized based on actual volumes of natural gas and oil sold to purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of our proportionate share of the remaining recoverable reserves on the underlying properties.

Derivative Instruments

Commodity derivative financial instruments (e.g., swaps, floors, collars, and put options) are used to reduce the impact of natural gas and oil price fluctuations. Interest rate swaps are used to manage exposure to interest rate volatility, primarily as a result of variable rate borrowings under credit facilities. Every derivative instrument is recorded in the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative s fair value are recognized currently in earnings as we have not elected hedge accounting for any of our derivative positions.

Income Tax

Our predecessor was organized as a pass-through entity for federal income tax purposes. As a result, members are responsible for federal income taxes on their share of our taxable income. Certain of our predecessor s consolidated subsidiaries are taxed as corporations and subject to federal income taxes. Our predecessor was also subject to the Texas margin tax and certain aspects of the tax make it similar to an income tax as the tax is assessed on 1% of taxable margin apportioned to operations in Texas. Deferred taxes arise due to temporary differences between the financial statement carrying value of existing assets and liabilities and their respective tax basis.

Our predecessor had to recognize the tax effects of any uncertain tax positions it may adopt if the position taken is more likely than not sustainable based on its technical merits. If a tax position meets such criteria, the tax effect that would be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized. There were no uncertain tax positions that required recognition in the financial statements at December 31, 2013 or 2012.

Following our initial public offering, we are treated as a taxable C corporation and are subject to federal and certain state income taxes. Accordingly, a pro forma income tax provision has been disclosed as if our predecessor was a taxable corporation for the years ended December 31, 2013 and 2012. A pro forma effective tax rate of 36.06% and 35.39% was used for the years ended December 31, 2013 and 2012, respectively. If MRD LLC had affected the change in tax status on December 31, 2013, MRD LLC would have recognized a deferred tax liability of approximately $114.9 million primarily related to the tax basis of its long-lived assets being less than its book basis in those assets. MRD LLC would not have recognized any material deferred tax assets.

Unaudited Pro Forma Earnings Per Share

MRD LLC has presented pro forma earnings per share for the years ended December 31, 2013 and 2012. Pro forma net income (loss) per basic and diluted share was determined by dividing the pro forma net income (loss) by the number of common shares that were expected to be outstanding immediately following our initial public offering.

Off Balance Sheet Arrangements

As of September 30, 2014, we had no off balance sheet arrangements.

Recently Issued Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus.

Emerging Growth Company

Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term market risk refers to the risk of loss arising from adverse changes in natural gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity Price Risk

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of natural gas and oil prices. Natural gas and oil prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on the prices of natural gas and oil and our ability to maintain and increase production through acquisitions and exploitation and development projects.

To reduce the impact of fluctuations in natural gas and oil prices on our revenues, or to protect the economics of property acquisitions, we periodically enter into derivative contracts with respect to a portion of our projected natural gas and oil production through various transactions that fix the future prices received. These transactions may include price swaps, whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive

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the excess, if any, of the fixed floor over the floating rate or pays the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support natural gas and oil prices at targeted levels and to manage our exposure to natural gas and oil price fluctuations. We do not enter derivative contracts for speculative trading purposes. Our revolving credit facility contains various covenants and restrictive provisions which, among other things, limit our ability to enter into commodity price hedges exceeding a certain percentage of production.

For additional information regarding the volumes of our production covered by commodity derivative contracts and the average prices at which production is hedged as of September 30, 2014, December 31, 2013 and December 31, 2012, see the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus as well as the tables below.

At September 30, 2014, the MRD Segment had the following open commodity positions:

	Remaining 2014	2015	2016	2017	2018
Natural Gas Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (MMBtu)	4,540,000	2,250,000	1,670,000	1,270,000	1,500,000
Weighted-average fixed price	$ 4.18	$ 4.08	$ 4.18	$ 4.30	$ 4.30
Collar contracts:					
Average Monthly Volume (MMBtu)	730,000	1,580,000	1,100,000	1,050,000	
Weighted-average floor price	$ 4.11	$ 4.14	$ 4.00	$ 4.00	$
Weighted-average ceiling price	$ 5.15	$ 4.61	$ 4.71	$ 5.06	$
TGT Z1 basis swaps:					
Average Monthly Volume (MMBtu)	2,270,000	1,730,000	220,000	200,000	
Spread	$ (0.08)	$ (0.09)	$ (0.08)	$ (0.08)	$
Crude Oil Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (Bbls)	56,000	33,500		9,500	7,625
Weighted-average fixed price	$ 94.43	$ 93.86	$	$ 87.62	$ 87.00
Collar contracts:					
Average Monthly Volume (Bbls)	12,000	2,000	27,000		
Weighted-average floor price	$ 86.67	$ 85.00	$ 80.00	$	$
Weighted-average ceiling price	$ 112.33	$ 101.35	$ 99.70	$	$
Put option contracts:					
Average Monthly Volume (Bbls)		26,000			
Weighted-average fixed price	$	$ 85.00	$	$	$
Weighted-average deferred premium	$	$ (3.80)	$	$	$
NGL Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (Bbls)	184,000	151,000	148,500		
Weighted-average fixed price	$ 44.84	$ 41.61	$ 39.75	$	$

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At September 30, 2014, the MEMP Segment had the following open commodity positions:

	Remaining 2014	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (MMBtu)	2,580,200	2,605,278	2,692,442	2,450,067	2,160,000	1,914,583
Weighted-average fixed price	$ 4.34	$ 4.28	$ 4.40	$ 4.31	$ 4.51	$ 4.75
Collar contracts:						
Average Monthly Volume (MMBtu)	340,000	350,000				
Weighted-average floor price	$ 5.00	$ 4.62	$	$	$	$
Weighted-average ceiling price	$ 6.31	$ 5.80	$	$	$	$
Call spreads(1):						
Average Monthly Volume (MMBtu)	120,000	80,000				
Weighted-average sold strike price	$ 5.17	$ 5.25	$	$	$	$
Weighted-average bought strike price	$ 6.53	$ 6.75	$	$	$	$
Basis swaps:						
Average Monthly Volume (MMBtu)	2,830,000	2,940,000	1,635,000	300,000		
Spread	$ (0.09)	$ (0.12)	$ (0.06)	$ (0.05)	$	$
Crude Oil Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	283,452	314,281	332,813	326,600	312,000	160,000
Weighted-average fixed price	$ 95.83	$ 90.96	$ 85.83	$ 84.38	$ 83.74	$ 85.52
Collar contracts:						
Average Monthly Volume (Bbls)	23,000	5,000				
Weighted-average floor price	$ 82.83	$ 80.00	$	$	$	$
Weighted-average ceiling price	$ 105.31	$ 94.00	$	$	$	$
Basis swaps:						
Average Monthly Volume (Bbls)	134,000	97,500				
Spread	$ (4.32)	$ (7.07)	$	$	$	$
NGL Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	167,500	149,200	55,000			
Weighted-average fixed price	$ 43.13	$ 43.02	$ 39.28	$	$	$

(1) These transactions were entered into for the purpose of eliminating the ceiling portion of certain collar arrangements, which effectively converted the applicable collars into swaps.

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At December 31, 2013, the MRD Segment had the following open commodity positions:

	2014	2015	2016	2017
Natural Gas Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (MMBtu)	1,190,000	880,000	670,000	520,000
Weighted-average fixed price	$ 4.10	$ 4.19	$ 4.32	$ 4.45
Collar contracts:				
Average Monthly Volume (MMBtu)	330,000	130,000		
Weighted-average floor price	$ 4.09	$ 4.00	$	$
Weighted-average ceiling price	$ 5.24	$ 4.64	$	$
Basis swaps:				
Average Monthly Volume (MMBtu)	270,000	180,000	220,000	200,000
Spread	$ (0.07)	$ (0.09)	$ (0.08)	$ (0.08)
Crude Oil Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	18,000	6,000		
Weighted-average fixed price	$ 91.66	$ 88.50	$	$
Collar contracts:				
Average Monthly Volume (Bbls)	8,000	2,000		
Weighted-average floor price	$ 85.00	$ 85.00	$	$
Weighted-average ceiling price	$ 117.50	$ 101.35	$	$
NGL Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	18,000			
Weighted-average fixed price	$ 64.27	$	$	$

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At December 31, 2013, the MEMP Segment had the following open commodity positions:

	2014	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (MMBtu)	2,575,458	2,145,278	2,342,442	2,230,067	2,060,000	1,814,583
Weighted-average fixed price	$ 4.34	$ 4.30	$ 4.42	$ 4.31	$ 4.52	$ 4.77
Collar contracts:						
Average Monthly Volume (MMBtu)	340,000	350,000				
Weighted-average floor price	$ 4.93	$ 4.62	$	$	$	$
Weighted-average ceiling price	$ 6.12	$ 5.80	$	$	$	$
Call spreads(1):						
Average Monthly Volume (MMBtu)	120,000	80,000				
Weighted-average sold strike price	$ 5.08	$ 5.25	$	$	$	$
Weighted-average bought strike price	$ 6.31	$ 6.75	$	$	$	$
Basis swaps:						
Average Monthly Volume (MMBtu)	2,822,083					
Spread	$ (0.09)	$	$	$	$	$
Crude Oil Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	136,444	148,281	142,313	130,600	122,000	40,000
Weighted-average fixed price	$ 95.82	$ 93.07	$ 86.85	$ 85.96	$ 85.62	$ 85.00
Collar contracts:						
Average Monthly Volume (Bbls)	23,000	5,000				
Weighted-average floor price	$ 82.83	$ 80.00	$	$	$	$
Weighted-average ceiling price	$ 105.31	$ 94.00	$	$	$	$
Basis swaps:						
Average Monthly Volume (Bbls)	57,292	57,500				
Spread	$ (9.21)	$ (9.73)	$	$	$	$
NGL Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	118,500	112,800				
Weighted-average fixed price	$ 36.23	$ 35.04	$	$	$	$

(1) These transactions were entered into for the purpose of eliminating the ceiling portion of certain collar arrangements, which effectively converted the applicable collars into swaps.

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At December 31, 2012, the MRD Segment had the following open commodity positions:

	2013	2014	2015
Natural Gas Derivative Contracts:			
Fixed price swap contracts:			
Average Monthly Volume (MMBtu)	961,000	540,000	210,000
Weighted-average fixed price	$ 4.08	$ 3.96	$ 4.09
Collar contracts:			
Average Monthly Volume (MMBtu)	661,000	430,000	130,000
Weighted-average floor price	$ 4.61	$ 4.18	$ 4.00
Weighted-average ceiling price	$ 5.56	$ 5.10	$ 4.64
Basis swaps:			
Average Monthly Volume (MMBtu)	230,000	230,000	390,000
Spread	$ (0.09)	$ (0.09)	$ (0.09)
Crude Oil Derivative Contracts:			
Fixed price swap contracts:			
Average Monthly Volume (Bbls)	6,000		
Weighted-average fixed price	$ 98.44	$	$
Collar contracts:			
Average Monthly Volume (Bbls)	22,750	14,000	2,000
Weighted-average floor price	$ 84.66	$ 87.86	$ 85.00
Weighted-average ceiling price	$ 108.89	$ 111.34	$ 101.35
NGL Derivative Contracts:			
Fixed price swap contracts:			
Average Monthly Volume (Bbls)	28,500	2,000	
Weighted-average fixed price	$ 54.12	$ 84.00	$

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At December 31, 2012, the MEMP Segment had the following open commodity positions:

	2013	2014	2015	2016	2017	2018
Natural Gas Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (MMBtu)	1,017,672	1,462,125	1,156,112	1,113,275	1,020,067	900,000
Weighted-average fixed price	$ 4.35	$ 4.38	$ 4.28	$ 4.53	$ 4.30	$ 4.75
Collar contracts:						
Average Monthly Volume (MMBtu)	1,014,000	340,000	350,000			
Weighted-average floor price	$ 4.76	$ 4.93	$ 4.62	$	$	$
Weighted-average ceiling price	$ 5.82	$ 6.12	$ 5.80	$	$	$
Call spreads(1):						
Average Monthly Volume (MMBtu)	430,000	120,000	80,000			
Weighted-average sold strike price	$ 4.59	$ 5.08	$ 5.25	$	$	$
Weighted-average bought strike price	$ 5.84	$ 6.31	$ 6.75	$	$	$
Basis swaps:						
Average Monthly Volume (MMBtu)	813,432	1,318,750				
Spread	$ (0.11)	$ (0.09)	$	$	$	$
Crude Oil Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	70,632	35,102	12,031	11,013	10,000	
Weighted-average fixed price	$ 103.32	$ 94.27	$ 90.29	$ 90.39	$ 88.30	$
Collar contracts:						
Average Monthly Volume (Bbls)	36,750	52,158	50,000	44,000	42,000	
Weighted-average floor price	$ 84.73	$ 90.51	$ 89.00	$ 85.00	$ 85.00	$
Weighted-average ceiling price	$ 108.07	$ 107.03	$ 103.31	$ 103.40	$ 99.00	$
Call contracts:						
Average Monthly Volume (Bbls)	10,000					
Weighted-average fixed price	$ 115.00	$	$	$	$	$
NGL Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	30,805	16,300				
Weighted-average fixed price	$ 53.19	$ 58.91	$	$	$	$

(1) These transactions were entered into for the purpose of eliminating the ceiling portion of certain collar arrangements, which effectively converted the applicable collars into swaps.

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Interest Rate Risk

Periodically, we enter into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates such as those in our credit agreement to fixed interest rates. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for additional information regarding fixed-for-floating interest rate swap open positions as of September 30, 2014, December 31, 2013 and December 31, 2012 as well as the tables below.

At September 30, 2014, we had the following interest rate swap open positions:

Credit Facility	Remaining 2014	2015	2016
MEMP:			
Average Monthly Notional (in thousands)	$ 248,333	$ 280,833	$ 150,000
Weighted-average fixed rate	1.299%	1.416%	1.193%
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR

At December 31, 2013, we had the following interest rate swap open positions:

Credit Facility	2014	2015	2016
MEMP:			
Average Monthly Notional (in thousands)	$ 173,958	$ 280,833	$ 150,000
Weighted-average fixed rate	1.306%	1.416%	1.193%
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR
WildHorse Resources:			
Average Monthly Notional (in thousands)	$ 118,750	$ 100,000	$
Weighted-average fixed rate	0.773%	0.758%	
Floating rate	1 Month LIBOR	1 Month LIBOR	

At December 31, 2012, we had the following interest rate swap open positions:

Credit Facility	2013	2014	2015	2016
MEMP:				
Average Monthly Notional (in thousands)	$ 162,500	$ 150,000	$ 150,000	$ 150,000
Weighted-average fixed rate	1.148%	1.193%	1.193%	1.193%
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR
WildHorse Resources:				
Average Monthly Notional (in thousands)	$ 150,667	$ 118,750	$ 100,000	$
Weighted-average fixed rate	0.779%	0.773%	0.758%	
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR	
Tanos:				
Average Monthly Notional (in thousands)	$ 30,000	$	$	$
Weighted-average fixed rate	1.362%			
Floating rate	1 Month LIBOR			
WHT:				
Average Monthly Notional (in thousands)	$ 75,000	$ 25,000	$	$

Weighted-average fixed rate	1.510%	1,510%		
Floating rate	1 Month LIBOR	1 Month LIBOR		
			$	
Previous Owners:				
Average Monthly Notional (in thousands)	$ 11,500	$ 5,750		$
Weighted-average fixed rate	0.500%	0.500%	$	
Floating rate	1 Month LIBOR	1 Month LIBOR		

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Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives and the sale of our oil and gas production, which we market to energy companies.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates the credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market-makers. The creditworthiness of our counterparties is subject to periodic review. As of September 30, 2014, our derivative contracts are with major financial institutions, certain of which are also lenders under our revolving credit facilities. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for additional information.

We are also subject to credit risk due to the concentration of our natural gas and oil receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

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BUSINESS

We have two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

- MRD reflects the combined operations of the Company, MRD LLC, WildHorse Resources and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.

- MEMP reflects the combined operations of MEMP, its previous owners, and historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

Because we control MEMP through our ownership of its general partner, its business and operations are consolidated with ours for financial reporting purposes, even though we do not own any of its limited partner interests. As a result, our financial statements and notes thereto included elsewhere in this prospectus consolidate MEMP s business and assets with ours. However, except where expressly noted to the contrary, the following discussion of our business, operations and assets and the use of the terms we , our and us excludes MEMP s business, operations and assets. See MEMP for information regarding MEMP s business and assets. In addition, because BlueStone, MRD Royalty, MRD Midstream and Classic Pipeline were not included in the assets that MRD LLC contributed to us in connection with the restructuring transactions, unless stated otherwise, the information in this section does not include BlueStone, MRD Royalty, MRD Midstream or Classic Pipeline.

We are an independent natural gas and oil company focused on the exploitation, development, and acquisition of natural gas, NGL and oil properties with a majority of our activity in the Terryville Complex of North Louisiana, where we are targeting overpressured, liquids-rich natural gas opportunities in multiple zones in the Cotton Valley formation. As of December 31, 2013, our total leasehold position was 347,458 gross (205,818 net) acres, of which 60,041 gross (51,522 net) acres are in what we believe to be the core of the Terryville Complex. We are focused on creating shareholder value primarily through the development of our sizeable horizontal inventory.

MEMP is engaged in the acquisition, exploitation, development and production of oil and natural gas properties, with assets consisting primarily of producing oil and natural gas properties that are principally located in East Texas/North Louisiana, the Rockies, South Texas, the Permian and offshore Southern California. Most of MEMP s properties are located in large, mature oil and natural gas reservoirs with well-known geologic characteristics and long-lived, predictable production profiles and modest capital requirements. MEMP is focused on generating stable cash flows, to allow MEMP to make quarterly cash distributions to its unitholders and, over time, to increase those quarterly cash distributions.

MRD

Overview

As of December 31, 2013, we had 1,582 gross (1,091 net) identified horizontal drilling locations, of which 1,431 gross (994 net) identified horizontal drilling locations are located in the Terryville Complex. These total gross identified horizontal drilling locations represent an inventory of over 42 years based on our expected 2014 drilling program. We believe our inventory to be repeatable and capable of generating high returns based on the extensive production history in the area, the results of our horizontal wells drilled to date, and the consistent reservoir quality across multiple target formations. As of December 31, 2013, we had estimated proved, probable and possible reserves of approximately

1,126 Bcfe, 800 Bcfe and 1,711 Bcfe, respectively. As of such date, we operated 98% of our proved reserves, 71% of which were natural gas. For the nine months ended September 30, 2014, 56% of our pro forma MRD Segment revenues were attributable to natural gas production, 22% to NGLs and 22% to oil. For the nine months ended September 30, 2014, we generated pro forma MRD Segment Adjusted EBITDA of $259 million and pro forma net loss of $914 million, and made pro forma capital expenditures of

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$268 million. For the year ended December 31, 2013, we generated pro forma MRD Segment Adjusted EBITDA of $159 million and pro forma net loss of $2.9 million, and made pro forma total capital expenditures of $203 million. Please see Summary Historical Consolidated and Combined Pro Forma Financial Data Adjusted EBITDA for an explanation of the basis for the pro forma presentation and our use of Adjusted EBITDA to measure the MRD Segment s profitability.

Our average net daily production for the nine months ended September 30, 2014 was approximately 208 MMcfe/d (approximately 76% natural gas, 17% NGLs and 7% oil) and our reserve life was 14.8 years. The Terryville Complex represented 84% of our total net production for the nine months ended September 30, 2014. As of December 31, 2013, we produced from 95 horizontal wells and 800 vertical wells. Since January 1, 2014, in the Terryville Complex we have completed and brought online 21 horizontal wells through September 30, 2014, bringing our total number of producing horizontal wells to 41 in our primary formations.

The following chart provides information regarding our production growth and the increasing proportion of our horizontal well production since the beginning of 2012.

Our Properties

Cotton Valley Overview

The Cotton Valley formation extends across East Texas, North Louisiana and Southern Arkansas. The formation has been under development since the 1930s and is characterized by thick, multi-zone natural gas and oil reservoirs with well-known geologic characteristics and long-lived, predictable production profiles. Over 21,000 vertical wells have been completed throughout the play. In 2005, operators started redeveloping the Cotton Valley using horizontal drilling and advanced hydraulic fracturing techniques. To date, operators have drilled over 600 horizontal Cotton Valley wells. Some large, analogous redevelopment projects in the Cotton Valley include the Nan-Su-Gail Field in Freestone County, East Texas, where over 40 horizontal wells have been drilled by operators such as Devon Energy Corporation and Marathon Oil Corporation, and the Carthage Complex in Panola County, East Texas, where operators such as ExxonMobil Corporation, BP America, Memorial Production Partners LP and Anadarko Petroleum Corporation have drilled over 153 horizontal wells.

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Cotton Valley Terryville Complex Horizontal Redevelopment

We are currently engaged in the horizontal redevelopment of the Terryville Complex in Lincoln Parish, Louisiana utilizing horizontal drilling and completion techniques similar to those employed at the Nan-Su-Gail Field, Carthage Complex in East Texas and other major resource plays across the United States. We have assembled a largely contiguous acreage position in the Terryville Complex of approximately 60,041 gross (51,522 net) acres as of December 31, 2013. The majority of our current and planned development is focused in and around what we believe to be the core of the Terryville Complex.

We entered the Terryville Complex via an acquisition from Petrohawk Energy Corporation in April 2010, with the goal of redeveloping the field with horizontal drilling and modern completion techniques. Since that acquisition, we have completed multiple bolt-on acquisitions and in-fill leases to build our current position. We believe the Terryville Complex, which has been producing since 1954, is one of North America s most prolific natural gas fields, characterized by high recoveries relative to drilling and completion costs, high initial production rates with high liquids yields, long reserve life, multiple stacked producing zones, available infrastructure and a large number of service providers.

After initially drilling eight vertical pilot wells in the Terryville Complex, we commenced a horizontal drilling program in 2011 to further delineate and define our position. In 2013, we shifted our operational focus to full-scale horizontal redevelopment of the Terryville Complex, going from two rigs to four rigs by the end of that year. Additionally, in the fourth quarter of 2013, we moved to drilling on multi-well pads that allow us to more efficiently drill wells and control costs as we develop our stacked pay zones. We intend to dedicate approximately $304 million of our $351 million drilling and completion budget in 2014 to develop multiple zones within the Terryville Complex, where we expect to drill 33 gross (29 net) horizontal wells and 3 gross (2.7 net) vertical wells. Our horizontal redevelopment program in the Terryville Complex will be focused on increasing our well performance and recoveries.

Within the Terryville Complex, as of December 31, 2013, we had 945 Bcfe, 688 Bcfe and 1,643 Bcfe of estimated proved, probable and possible reserves, respectively, and a drilling inventory consisting of 1,431 gross (994 net) identified horizontal drilling locations, including 91 gross (72 net) drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013. Since initiating our horizontal drilling program in 2011, we have drilled 44 gross (38 net) horizontal wells. Within the Terryville Complex, on a proved reserves basis, we operate approximately 99% of our existing acreage and hold an average working interest of approximately 74% across our acreage. Our high operating control allows us to more efficiently and economically manage the redevelopment of this extensive resource.

We believe seismic data, as well as information gathered from the results of our existing 275 vertical and 46 horizontal wells throughout the field, support the existence of at least ten stacked pay zones across the Terryville Complex. Our redevelopment program currently targets four of the stacked pay zones in the Cotton Valley formation zones we term the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink, all of which we are developing with horizontal wells through pad drilling. These four zones have an overall thickness ranging from 400 to 890 feet across our acreage position. We believe the overpressured nature of this section of the Cotton Valley formation is highly productive when accessed through horizontal drilling and fracture stimulation technologies. These qualities, when combined with the liquids-rich nature of the natural gas, high initial rates of production and competitive well costs, produce what we believe to be amongst the highest rate of return wells in the nation. Further, there are additional opportunities for redevelopment in the zones above the four main zones. NSAI has audited over $1 billion PV-10 and 677 Bcfe in our possible reserve category as of December 31, 2013 for the redevelopment of these additional zones. Please see Reserves.

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Our well results have shown consistency in initial production, decline rates and estimated ultimate recovery. The consistency of these results gives us confidence that the full-scale redevelopment of the Terryville Complex that we began in 2013 will continue to be successful. The table below details certain information on estimated ultimate recoveries and production on a gross basis for our 41 existing horizontal wells currently producing from our four primary target zones in the Terryville Complex to the extent such data is available as of the dates and for the periods presented below. The wells below highlight the consistency of our drilling results in the four primary target zones in which we plan to focus our future development activity.

	Lateral	Producing Wells EUR(1)				EUR			Cumulative Production				Gross Wellhead Flow Rates After Processing (MMcfe/d)(2)(3)				
Well Name	**Length (Feet)**	**(Bcfe)**	**%Gas**	**%NGL**	**%Oil**	**Bcfe/ 1,000**	**First Production**	**Days Producing**	**(Bcfe)**	**%Gas**	**%NGL**	**%Oil**	**0-30**	**0-90**	**91-180**	**181-360**	**D&C ($MM)**
Upper Red Zone																	
LD Barnett 23H-2	4,015	12.3	69%	27%	4%	3.1	1/30/2012	975	5.0	71%	24%	5%	14.5	12.0	7.7	5.6	6.7
Colquitt 20 17H-1	4,357	11.5	79%	18%	2%	2.6	7/30/2012	793	4.3	81%	17%	2%	17.5	12.6	7.2	5.1	7.8
Dowling 22 15H-1	5,376	9.4	78%	20%	2%	1.8	9/22/2012	739	5.7	80%	18%	3%	16.3	15.6	11.1	8.2	8.8
Nobles 13H-1	4,216	9.1	67%	24%	10%	2.1	11/17/2012	683	4.6	65%	22%	13%	21.5	16.7	9.9	6.5	7.8
Sidney McCullin 16 21H-1	4,604	13.8	75%	21%	3%	3.0	1/19/2013	620	5.0	81%	16%	3%	17.4	14.2	10.8	8.4	8.1
Wright 14 11 HC-1	5,250	11.9	66%	27%	7%	2.3	5/27/2013	492	5.5	64%	28%	8%	19.6	18.1	16.1	8.4	8.8
BF Fallin 22 15H-1	5,122	12.3	72%	24%	4%	2.4	6/17/2013	471	3.9	74%	22%	4%	14.8	13.7	11.8	5.9	7.5
Dowling 20 17H-1	4,327	9.0	73%	25%	3%	2.1	7/22/2013	436	2.6	77%	20%	3%	15.2	11.0	5.7	4.5	10.7
Gleason 31H-1	3,692	2.4	91%	9%	0%	0.7	8/12/2013	415	0.6	90%	10%	0%	2.9	2.3	1.6	1.2	9.5
Burnett 26H-1	2,405	5.5	71%	25%	4%	2.3	9/22/2013	374	1.2	71%	24%	5%	6.9	5.6	3.5	2.4	6.9
Drewett 17 8H-1	4,010	15.6	66%	25%	10%	3.9	11/13/2013	322	3.9	61%	26%	13%	22.1	18.6	11.9		7.7
Wright 13 12 HC-2	6,009	24.0	69%	22%	10%	4.0	12/21/2013	284	4.6	76%	11%	13%	22.7	19.6	16.3		8.5
LA Minerals 15 22H-2	5,814	17.3	73%	25%	3%	3.0	1/21/2014	253	3.4	76%	22%	3%	17.8	16.1	13.4		8.8
Wright 13 24 HC-3	6,606	20.9	74%	23%	3%	3.2	4/14/2014	170	3.4	85%	11%	4%	30.3	24.6			10.8
Wright 13 24 HC-1	6,678	15.5	71%	20%	8%	2.3	4/14/2014	170	2.8	77%	12%	11%	25.0	20.4			11.8
TL McCrary 14 11 HC-5	5,875	30.0	71%	24%	6%	5.1	4/14/2014	170	3.0	81%	11%	8%	22.9	23.3			10.2
LA Minerals 19 30 HC-2	6,912	15.1	75%	24%	2%	2.2	5/29/2014	125	2.3	85%	13%	2%	25.1	20.4			10.8
LA Minerals 19 30 HC-1	6,519	19.6	75%	23%	1%	3.0	6/1/2014	122	2.0	85%	13%	2%	21.5	17.7			11.6
Werner 29H-1	3,410	4.7	75%	23%	2%	1.4	8/13/2014	49	0.4	84%	13%	2%	8.6				11.0
Werner 29 32 5 HC-1	6,810	9.7	74%	23%	3%	1.4	8/13/2014	49	0.8	84%	13%	3%	18.4				10.4
Werner 29 32 5 HC-2	8,300	16.5	75%	23%	2%	2.0	8/13/2014	49	1.2	84%	13%	3%	26.1				12.2
Temple 8H-1	2,403	6.3	77%	23%	0%	2.6	8/24/2014	38	0.4	93%	7%	0%	12.7				9.6
Temple 8 17 HC-1	6,210	2.9	76%	23%	1%	0.5	8/29/2014	33	0.3	92%	7%	1%	8.4				11.9
TL McCrary 14 11 HC-2	4,401	NA					9/25/2014	6	0.1								7.7
TL McCrary 14 11 HC-4	4,810	NA					9/25/2014	6	0.0								9.0
Lower Red Zone																	
TL McCrary 14H-1	4,544	12.7	70%	27%	4%	2.8	5/1/2012	883	4.5	73%	23%	4%	14.4	11.7	8.3	5.4	7.7
Nobles 13H-2	4,060	5.6	66%	23%	11%	1.4	11/17/2012	683	3.3	68%	22%	10%	16.0	11.9	8.2	5.2	7.8
LA Methodist Orphanage 14H-1	3,637	9.5	69%	24%	7%	2.6	2/15/2013	593	4.0	69%	23%	8%	13.9	13.0	9.7	6.3	9.1

Dowling 21 16H-1	4,590	8.4	78%	21%	1%	1.8	3/18/2013	562	3.0	84%	15%	2%	13.0	10.1	6.5	4.5	6.6
Drewett 17 8H-2	3,700	4.2	66%	25%	9%	1.1	11/13/2013	322	1.2	63%	27%	11%	8.7	6.2	3.2		7.0
Wright 13 12 HC-1	5,409	9.4	70%	21%	9%	1.7	12/21/2013	284	2.2	76%	11%	13%	14.7	11.4	7.2		9.3
LA Minerals 15 22H-1	5,926	8.1	71%	24%	5%	1.4	1/21/2014	253	1.9	73%	21%	5%	13.8	10.9	6.4		7.8
Wright 13 24 HC-4	6,518	15.1	74%	23%	3%	2.3	4/14/2014	170	2.6	85%	11%	4%	25.7	19.6			13.4
LA Minerals 19 30 HC-3	5,356	2.5	76%	21%	3%	0.5	5/29/2014	125	0.6	84%	13%	3%	8.8	5.9			12.1
LA Minerals 19 30 HC-4	6,469	3.5	77%	21%	2%	0.5	6/1/2014	122	0.9	85%	13%	2%	13.6	8.5			13.8
TL McCrary 14 11 HC-1	4,010	NA					9/25/2014	6	0.0								8.9
TL McCrary 14 11 HC-3	4,620	NA					9/25/2014	6	0.0								8.3
Lower Deep Pink Zone																	
LA Methodist Orphanage 14H-2	3,550	6.1	68%	23%	9%	1.7	2/15/2013	593	3.5	67%	22%	11%	14.2	11.6	7.6	5.7	6.1
Wright 13 12 HC-4	5,010	5.8	69%	21%	10%	1.2	12/21/2013	284	1.6	75%	11%	13%	11.8	8.8	4.8		7.0
Wright 13 12 HC-3	5,706	5.4	71%	20%	8%	0.9	12/21/2013	284	1.6	77%	12%	11%	12.5	9.3	5.0		7.4
Upper Deep Pink Zone																	
Werner 29 32 5 HC-3	6,679	3.1	73%	22%	4%	0.5	8/13/2014	49	0.3	81%	13%	6%	7.2				10.1
Averages(4)																	
All Wells	**5,071**	**10.7**	**73%**	**23%**	**5%**	**2.1**		**319**	**2.4**	**78%**	**17%**	**6%**	**16.1**	**13.6**	**8.4**	**5.6**	**9.2**
Upper Red	**5,125**	**12.8**	**73%**	**23%**	**4%**	**2.5**		**314**	**2.7**	**79%**	**16%**	**5%**	**17.7**	**15.7**	**9.8**	**5.6**	**9.4**
Lower Red	**4,903**	**7.9**	**72%**	**23%**	**5%**	**1.6**		**334**	**2.0**	**76%**	**18%**	**6%**	**14.3**	**10.9**	**7.1**	**5.4**	**9.3**
Lower Deep Pink	**4,755**	**5.8**	**69%**	**21%**	**9%**	**1.3**		**387**	**2.2**	**73%**	**15%**	**12%**	**12.8**	**9.9**	**5.8**	**5.7**	**6.8**
Upper Deep Pink	**6,679**	**3.1**	**73%**	**22%**	**4%**	**0.5**		**49**	**0.3**	**81%**	**13%**	**6%**	**7.2**				**10.1**

(1) EUR represents the Estimated Ultimate Recovery or sum of total gross remaining proved reserves attributable to each location in our recent reserve report and cumulative sales from such location. EUR is shown on a combined basis for oil/condensates, gas and NGLs, after the effects of processing.

(2) Production data is as of September 30, 2014 and shown gross on a combined basis after the effects of processing.

(3) Periodic flow rates start on day 4, with days 1 through 3 used to allow clean up associated with well completion. The 30-day flow rates therefore start on day 4 and continue 30 days to day 33 and the 90-day flow rates go from day 4 to day 93.
(4) We also have five horizontal producing wells outside of the four primary target zones. These averages do not include such wells.

Cotton Valley Terryville Complex Proved Reserves Update

As of September 30, 2014, within the core Terryville Complex, we had proved reserves of 849 Bcfe based on our recent reserve report, and an aggregate drilling inventory of 1,411 gross identified drilling locations, taking into account drilling activity during the first nine months of 2014. The PV-10 of our proved reserves within the Terryville Complex as of September 30, 2014 was $1.6 billion. PV-10 is a non-GAAP financial measure and differs from standardized measure, the most directly comparable GAAP financial measure. Please see Reserves. SEC pricing for natural gas and oil used in calculating the PV-10 of such proved reserves as of September 30, 2014 was $4.23 per Mcf and $95.56 per Bbl, respectively, based on the unweighted average of the first-day-of-the-month prices for each of the twelve months preceding September 2014.

East Texas

We own and operate approximately 54,337 gross (42,894 net) acres as of December 31, 2013 in Texas, where we are currently producing primarily from the Cotton Valley, Travis Peak and Bossier formations and targeting the Cotton Valley formation for future development. From January 1, 2011 through December 31, 2013, we have drilled and completed 28 gross (10.3 net) wells and are operating one rig in East Texas as of December 31, 2013. In 2014, we plan to invest $29 million to drill 4 gross (4 net) wells in East Texas in the Joaquin Field of Panola and Shelby Counties. As of December 31, 2013, we had approximately 108 gross identified horizontal drilling locations in East Texas, including 54 gross (43 net) drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013. For the nine months ended September 30, 2014, our average net daily production from our East Texas properties was 27 MMcfe/d, of which 75% was natural gas. Within our East Texas properties, on a proved reserves basis, we operate approximately 94% of our existing properties.

Rockies

We own approximately 162,375 gross (66,191 net) acres as of December 31, 2013 in our Rockies region and for the nine months ended September 30, 2014 our average net daily production from this region was 6 MMcfe/d. In 2014, we plan to invest $18 million to complete 2 gross (2 net) vertical wells in the Tepee Field of the Piceance Basin targeting the Mancos and Williams Fork formations. As of December 31, 2013, we had approximately 174 gross identified vertical drilling locations in the Tepee Field in our Rockies properties.

Reserves

Our estimates of proved reserves are prepared by NSAI, and our estimates of probable and possible reserves are prepared by our management and audited by NSAI. As of December 31, 2013, we had 1,126 Bcfe, 800 Bcfe and 1,711 Bcfe of estimated proved, probable and possible reserves, respectively. As of this date, our proved reserves were 71% gas and 29% NGLs and oil. Additionally, the PV-10 of our proved reserves was $1,469 million, the PV-10 for our probable reserves was $1,052 million and the PV-10 for our possible reserves was $2,386 million. The following table provides summary information regarding our estimated proved, probable and possible reserves data by area based on our reserve report as of December 31, 2013 and our average net daily production by area for the nine months ended September 30, 2014:

	Proved Total (Bcfe)	% Gas	% Developed	Proved PV-10 (in millions)(1)	Probable Total (Bcfe)(2)	Probable PV-10 (in millions)(1)	Possible Total (Bcfe)(2)	Possible PV-10 (in millions)(1)	Average Net Daily Production (MMcfe/d)
Terryville Complex	945	71%	33%	$ 1,341	688	$ 1,032	1,643	$ 2,383	175
East Texas	175	75%	29%	110	109	18	66	3	27
Rockies	6	49%	100%	18	2	2	2	1	6
Total	1,126	71%	33%	$ 1,469	800	$ 1,052	1,711	$ 2,386	208

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(1) In this prospectus, we have disclosed our PV-10 based on our reserve report. PV-10 is a non-GAAP financial measure and represents the period-end present value of estimated future cash inflows from our natural gas and crude oil reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using SEC pricing assumptions in effect at the end of the period. SEC pricing for natural gas and oil of $3.67 per Mcf and $93.42 per Bbl was based on the unweighted average of the first-day-of-the-month prices for each of the twelve months preceding December 2013. PV-10 differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes. Moreover, GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves. Because PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized estimates of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Nonetheless, we believe that PV-10 estimates for reserve categories other than proved present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. In addition, investors should be cautioned that estimates of PV-10 for probable and possible reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Our PV-10 estimates of proved reserves and our standardized measure are equivalent as of December 31, 2013 because, prior to the completion of our initial public offering, we were not subject to entity level taxation. Accordingly, no provision for federal income taxes has been provided because taxable income for 2013 was passed through to our equity holders. However, had we not been a tax exempt entity as of December 31, 2013, our estimated discounted future income tax in respect of our proved, probable and possible reserves would have been approximately $401 million, $368 million and $835 million, respectively. Since the closing of our initial public offering, we are treated as a taxable entity for federal income tax purposes and our future income taxes will be dependent upon our future taxable income. Neither PV-10 nor standardized measure represents an estimate of fair market value of our natural gas and oil properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of estimated reserves held by companies without regard to the specific tax characteristics of such entities.

(2) Substantially all of our estimated probable and possible reserves are classified as undeveloped.

Drilling Inventory and Capital Budget

We intend to develop our multi-year drilling inventory by utilizing our significant expertise in horizontal drilling and fracture stimulation to grow our production, reserves and cash flow. During 2013, we invested approximately $190 million of capital to drill 31 gross (21.3 net) wells. A substantial portion of our development program is focused on horizontal drilling of liquids rich wells in the Terryville Complex, where we spent approximately $163 million in capital expenditures to drill 15 gross (12.1 net) horizontal wells during 2013.

For 2014, we have budgeted a total of $351 million to drill 39 gross (34 net) operated horizontal wells, which includes $268.7 million of capital expenditures we made during the nine months ended September 30, 2014 (including $225.7 million of capital expenditures we made in the Terryville Complex). We expect to fund our 2014 development primarily from cash flows from operations. The majority of our drilling locations and our 2014 development program are focused on the Terryville Complex, where we plan to invest $304 million on drilling 33 gross (29 net) horizontal wells and 3 gross (2.7 net) vertical wells. In the Terryville Complex, we plan to run six rigs for the remainder of 2014 targeting primarily our four primary zones within the Cotton Valley   the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. Total vertical depth of these zones ranges from 8,200 to 11,200 feet.

In our East Texas properties in the Joaquin Field, we plan to spend development capital of $29 million to drill 4 gross (4 net) horizontal wells targeting the Cotton Valley formation at vertical depths of 6,000 to 10,000 feet.

In our Rockies properties, we plan to spend $18 million of development capital, primarily in the Tepee Field in the Piceance Basin in Colorado focused on completing 2 gross (2 net) wells.

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The following table provides information regarding our acreage and drilling locations by area, as of December 31, 2013:

	Net Acreage	WI%	Gross Horizontal Drilling Locations(1)(2)(3) Proved	Probable	Possible	Management	Total Gross	Net	Gross Horizontal Drilling Inventory (years)
Terryville Complex	96,733	74%	91	147	450	743	1,431	994	43
East Texas	42,894	79%	54	39	15		108	92	27
Rockies	66,191	41%		23	20		43	4	
Total	205,818	59%	145	209	485	743	1,582	1,091	42

(1) The above table excludes 192 proved vertical drilling locations in our reserve report in the Terryville Complex and 174 identified vertical locations based on management estimates in the Rockies.
(2) Please see Business Our Operations Drilling Locations for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see Risk Factors Risks Related to Our Business Our identified drilling locations, which are scheduled out over many years, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. Proved, probable and possible locations are based on our reserve report. Management locations are based on management estimates of additional identified drilling locations.
(3) As of September 30, 2014, we had an aggregate drilling inventory of 1,411 identified gross horizontal inventory locations in the Terryville Complex, taking into account drilling activity during the first nine months of 2014. Please see Our Properties Cotton Valley Terryville Complex Proved Reserves Update.

Our extensive inventory and horizontal drilling program in the Terryville Complex is currently focused on four zones within the Cotton Valley formation the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. The table below sets forth our drilling locations by zone as of December 31, 2013 along with the average results for the wells we have drilled within each zone. Please see Business Our Properties Cotton Valley Terryville Complex Horizontal Redevelopment for more detail on our properties in the Terryville Complex.

Lower Cotton Valley Zone	Gross Horizontal Drilling Locations(1)(4) Proved	Probable	Possible	Management	Total	Average Historical Results(2) Producing Wells Drilled(1)	EUR (Bcfe)(3)	Drilling and Completion Costs ($MM)
Upper Red	47	42	40	313	442	25	12.8	$ 9.4
Lower Red	40	40	36	276	392	12	7.9	9.3
Lower Deep Pink	4	28	47	79	158	3	5.8	6.8
Upper Deep Pink		37	42	75	154	1	3.1	10.1
Other Zones			285		285			
Total Terryville Complex	91	147	450	743	1,431	41	10.7	$ 9.2

(1) Please see Business Our Operations Drilling Locations for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see Risk Factors Risks Related to Our Business Our identified drilling locations, which are scheduled out over many years, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. Proved, probable and possible locations are based on our reserve report. Management locations are based on management estimates of additional identified drilling locations.
(2) Relates to the 41 horizontal wells drilled by us in the four primary target zones in the Terryville Complex and included in our recent reserve report as proved developed reserves as of September 30, 2014.
(3) EUR represents the Estimated Ultimate Recovery or the sum of total gross remaining proved reserves attributable to each location in our recent reserve report and cumulative sales from such location. EUR is shown at the wellhead on a combined basis for oil/condensates and wet gas.
(4) As of September 30, 2014, we had an aggregate drilling inventory of 1,411 identified gross horizontal inventory locations in the Terryville Complex, taking into account drilling activity during the first nine months of 2014. Please see Our Properties Cotton Valley Terryville Complex Proved Reserves Update.

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Our Terryville horizontal development program in 2014 has an average working interest of 86% and our total horizontal development inventory has an average working interest of 69%.

For the Terryville Complex, our 2014 budget assumes an average drilling and completion cost of $9.5 million for gross horizontal wells ($8.3 million per net well) and is based on an average lateral length of 5,824 feet. As part of our long-term development plan, the lateral length of our planned wells is expected to increase and we expect wells within the Terryville Complex to increase to a 7,500 foot lateral length.

Business Strategies

Our primary objective is to build shareholder value through growth in reserves, production and cash flows by developing and expanding our significant portfolio of drilling locations. To achieve our objective, we intend to execute the following business strategies:

Grow production, reserves and cash flow through the development of our extensive drilling inventory. We believe our extensive inventory of low-risk drilling locations, combined with our operating expertise, will enable us to continue to deliver production, reserve and cash flow growth and create shareholder value. As of December 31, 2013, we had assembled an aggregate drilling inventory of 1,582 gross identified horizontal drilling locations, 90% of which are in the Terryville Complex, representing a drilling inventory of over 43 years based on our expected 2014 drilling program. We believe that the risk and uncertainty associated with our core acreage positions in the Terryville Complex has been largely reduced through our development activity, and because those positions are in areas with extensive drilling and production history. Since initiating our horizontal drilling program with one rig in 2011, we have invested over $521 million in the Terryville Complex through September 30, 2014. With six rigs running in the Terryville Complex as of September 30, 2014, we are one of the most active drillers in the Cotton Valley formation. We intend to dedicate approximately $304 million of our $351 million drilling and completion budget in 2014 to develop the overpressured liquids-rich Terryville Complex through multi-well pad drilling. We believe multiple vertically stacked producing horizons in the Terryville Complex can be developed using horizontal drilling techniques, thus enhancing the economics of this field.

Enhance returns through prudent capital allocation and continued improvements in operational and capital efficiencies. We continually monitor and adjust our drilling program with the objective of achieving the highest total returns on our portfolio of drilling opportunities. We believe we will achieve this objective by (i) minimizing the capital costs of drilling and completing horizontal wells through knowledge of the target formations, (ii) maximizing well production and recoveries by optimizing lateral length, the number of frac stages, perforation intervals and the type of fracture stimulation employed, (iii) targeting specific zones within our leasehold position to maximize our hydrocarbon mix based on the existing commodity price environment and (iv) minimizing operating costs through efficient well management.

Exploit additional development opportunities on current acreage. Our existing asset base provides numerous opportunities for our highly experienced technical team to create shareholder value by increasing our inventory beyond our currently identified drilling locations and ultimately by growing our estimated proved reserves. In the Terryville Complex, we are currently targeting multiple stacked horizons. We also believe our East Texas region has a significant inventory of low-risk, liquids-rich horizontal drilling locations. Finally, we continue to evaluate our leasehold positions in the Rockies and have preliminarily identified over 170 potential vertical locations.

Maintain a disciplined, growth oriented financial strategy. We intend to fund our growth primarily with internally generated cash flows while maintaining ample liquidity and access to the capital markets. Furthermore, we plan to hedge a significant portion of our expected production to reduce our exposure to downside commodity price fluctuations and enable us to protect our cash flows and maintain liquidity to fund our drilling program. Since approximately 76% of our acreage in the Terryville Complex was held by production as of December 31,

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2013 and no significant drilling commitments are needed to hold our remaining acreage in the near term, we are able to allocate capital among projects in a manner that optimizes both costs and returns, resulting in a highly efficient drilling program.

Make opportunistic acquisitions that meet our strategic and financial objectives. We will seek to acquire oil and gas properties that we believe complement our existing properties in our core areas of operation. In addition to our focus on the Terryville Complex, we are pursuing other properties that provide opportunities for the addition of reserves and production through a combination of exploitation, development, high-potential exploration and control of operations. We follow a technology driven strategy to establish large, contiguous leasehold positions in the core of prolific basins and opportunistically add to those positions through bolt-on acquisitions over time. We entered into the Terryville Complex through strategic acquisitions and grassroots leasing efforts, amassing a land position as of December 31, 2013 of 96,733 net acres, 51,522 net acres of which we believe to be in the core of the play. We will continue to identify and opportunistically acquire additional acreage and producing assets to complement our multi-year drilling inventory.

Competitive Strengths

We believe that the following strengths will allow us to successfully execute our business strategies.

Large, concentrated position in one of North America s leading plays. As of December 31, 2013, we owned approximately 60,041 gross (51,522 net) acres in what we believe to be the core of the Terryville Complex in Lincoln Parish, which we believe to be one of North America s most prolific liquids-rich natural gas fields, characterized by consistent and predictable geology and multiple stacked pay formations confirmed by extensive vertical well control. Through September 30, 2014, our drilling program in the Terryville Complex has produced some of the top performing gas wells in the United States in the previous two years, with single horizontal well results having achieved EURs averaging 10.7 Bcfe per well. Through September 30, 2014, we have brought 41 wells online within our four primary target zones with average 30-day initial production rates of 16.1 MMcfe/d and average drilling and completion costs of $9.2 million per well. Approximately 76% of our acreage in the Terryville Complex was held by production at December 31, 2013 and there are no significant lease expirations until 2017. Additionally, all of our acreage in this play can be held by running a one-rig program over the next 18 months.

De-risked acreage position with multi-year inventory of liquids-rich drilling opportunities. As of December 31, 2013, we had a drilling inventory consisting of 1,582 gross identified horizontal drilling locations, of which approximately 145 are gross proved undeveloped locations. Based on our expected 2014 drilling program and gross identified drilling locations, we have over 42 years of liquids-rich drilling inventory. The majority of our drilling activity has been and will continue to be focused in the Terryville Complex, where we produce liquids-rich natural gas from the overpressured Cotton Valley formation. We have used subsurface data from our vertical wells coupled with 3-D seismic data to identify and prioritize our inventory based on returns. This liquids-rich gas formation allows for NGL processing that, when coupled with the condensate produced, results in strong well economics. For the nine months ended September 30, 2014, 56% of our MRD Segment revenues were attributable to natural gas, 22% to NGLs and 22% to oil.

Significant operational control with low cost operations. On a proved reserves basis, we operate 99% of our properties and have operational control of all of our drilling inventory in the Terryville Complex. We believe maintaining operational control will enable us to enhance returns by implementing more efficient and cost-effective operating practices, through the selection of economic drilling locations, opportunistic timing of development, continuous improvement of drilling, completion and stimulation techniques and development on multi-well pads. As a result of the contiguous nature of our leasehold in the Terryville Complex, its geologic continuity and cross unit lateral pooling, we are able to drill consistently long laterals, averaging over 5,071 lateral feet, which helps us to reduce costs on a per-lateral foot basis and increase our returns. We expect the average lateral length of the 33 gross wells that we expect to drill in the Terryville Complex in 2014 to be 5,824 feet per well. Operating in mature basins in North Louisiana and East Texas allows us to take advantage of the

available and extensive midstream infrastructure and accelerate our development plan without encountering significant constraints in either takeaway or processing capacity. Our operational control allows us to focus on operating efficiency, which has resulted in our MRD Segment lease operating costs declining 35% from $0.50 per Mcfe for the nine months ended September 30, 2013 to $0.33 per Mcfe for the nine months ended September 30, 2014.

Proven and incentivized executive and technical team. We believe our management and technical teams are one of our principal competitive strengths due to our team s significant industry experience and long history of working together in the identification, execution and integration of acquisitions, cost efficient management of profitable, large scale drilling programs and a focus on rates of return. Additionally, our technical team has substantial expertise in advanced drilling and completion technologies and decades of expertise in operating in the North Louisiana and East Texas regions. The members of our management team collectively have an average of 22 years of experience in the oil and natural gas industry. John A. Weinzierl, our Chief Executive Officer, has 24 years of oil and natural gas industry experience as a petroleum engineer, a strong commercial and technical background and extensive experience acquiring and managing oil and natural gas properties. Our management team has a significant economic interest in us directly and through its equity interests in our controlling stockholder, MRD Holdco. We believe our management team is motivated to deliver high returns, create shareholder value and maintain safe and reliable operations.

Our relationship with MEMP. We own a 0.1% general partner interest in MEMP through our ownership of its general partner as well as 50% of MEMP s incentive distribution rights. MEMP s objective as a master limited partnership is to generate stable cash flows, allowing it to make quarterly distributions to its limited partners and, over time, to increase those quarterly distributions. As a result of its familiarity with our management team and our asset base and our track record of prior drop-down transactions, we believe that MEMP is a natural purchaser of properties from us that meet its acquisition criteria. We believe this mutually beneficial relationship enhances MEMP s ability to generate consistent returns on its oil and natural gas properties, provides us with a growing source of cash flow from our partnership interests in MEMP and allows us to monetize producing non-core properties. Since MEMP s initial public offering, we have consummated drop-down transactions with MEMP totaling approximately $391 million. In addition, we may have the opportunity to work jointly with MEMP to pursue certain acquisitions of oil and natural gas properties that may not otherwise be attractive acquisition candidates for either of us individually. While we believe that MEMP would be a preferred acquirer of our mature, non-core assets, we are under no obligation to offer to sell, and it is under no obligation to offer to buy, any of our properties.

Financial strength and flexibility. During 2013, we generated $159 million of pro forma MRD Segment Adjusted EBITDA and made pro forma total capital expenditures of $203 million. During the nine months ended September 30, 2014, we generated pro forma MRD Segment Adjusted EBITDA of $259 million and made pro forma capital expenditures of $268 million. We intend to continue to fund our organic growth predominantly with internally generated cash flows while maintaining ample liquidity for opportunistic acquisitions. We will continue to maintain a disciplined approach to spending whereby we allocate capital in order to optimize returns and create shareholder value. We seek to protect these future cash flows and liquidity levels by maintaining a three-to-five year rolling hedge program. As of September 30, 2014, our total liquidity, consisting of cash on hand and available borrowing capacity under our revolving credit facility, was approximately $650.2 million.

Initial Public Offering and Recent Developments

On June 18, 2014, we completed our initial public offering of 49,220,000 shares of common stock at a price to the public of $19.00 per share. Of the 49,220,000 shares offered, 21,500,000 were offered by us and 27,720,000 were offered by the selling stockholder, MRD Holdco. We did not receive any proceeds from the sale of shares by MRD Holdco. We used the net proceeds of approximately $380.2 million from our sale of shares in our initial public offering (i) to redeem the 10.00%/10.75% Senior PIK toggle notes due 2018 (the PIK notes) issued by MRD LLC in their entirety and to pay the applicable premium in connection with such redemption and accrued and unpaid interest to the date of redemption, (ii) together with borrowings of approximately $614.5

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million under our $2.0 billion revolving credit facility entered into in connection with the closing of our initial public offering, to make a cash payment to certain former management members of WildHorse Resources in connection with their contribution to us of their membership interests and incentive units in WildHorse Resources, (iii) to repay borrowings outstanding under WildHorse Resources revolving credit facility and second lien term loan, which we refer to collectively as WildHorse Resources credit agreements, (iv) to reimburse MRD LLC for interest paid on the PIK notes and (v) to pay costs associated with our revolving credit facility.

On July 10, 2014, we completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes (the MRD Senior Notes) at par. The MRD Senior Notes will mature on July 1, 2022. Interest on the MRD Senior Notes accrues from July 10, 2014 and will be payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2015. The net proceeds of approximately $586.0 million, after deducting the initial purchasers discounts and commissions and offering expenses, were used to repay a portion of the borrowings outstanding under our revolving credit facility. The amounts to be repaid under our revolving credit facility were incurred to repay the amounts outstanding under WildHorse Resources credit facilities in connection with the closing of our initial public offering. In conjunction with the closing of the offer and sale of the MRD Senior Notes, the borrowing base under our revolving credit facility was automatically decreased by $56.5 million.

On November 4, 2014, our wholly-owned subsidiary, Terryville Mineral & Royalty Partners LP (TRVL), filed a registration statement on Form S-1 with the SEC in connection with its proposed initial public offering of common units representing limited partner interests. In connection with the closing of the proposed offering, we will contribute to TRVL certain overriding royalty interests in approximately 27,000 gross acres in the Terryville Complex in exchange for limited partner interests in TRVL. The royalty interests will entitle TRVL to receive 7% of gross revenues from production within such acreage on all of our existing horizontal producing wells and future wells completed by us. TRVL intends to distribute the net proceeds from the proposed offering to us. A registration statement relating to these securities has been filed with the SEC but has not yet become effective. These securities may not be sold nor may any offers to buy be accepted prior to the time the registration statement becomes effective, and this prospectus does not constitute an offer to sell or a solicitation of any offers to buy these securities.

Acquisition History

We built out our leasehold positions in North Louisiana, East Texas and the Rocky Mountains primarily through the following acquisition activities:

- In November 2007, we acquired interests in the Joaquin Field, which is the core of our East Texas acreage;
- In December 2007, we acquired interests in the Tepee Field in the Piceance Basin in Colorado;
- In April and May 2010, we acquired interests in the Terryville Complex and other North Louisiana fields, which are the core of our North Louisiana acreage;
- In November 2010, we acquired interests in the Spider and E. Logansport Fields in North Louisiana;
- In May 2012, we acquired interests in the Terryville Complex and Double A Field in North Louisiana and East Texas;

In April 2013, we acquired interests in the West Simsboro and Simsboro Fields of the Terryville Complex in North Louisiana;

In November 2013, we acquired the remaining equity interests in Classic Hydrocarbons Holdings, L.P., Classic Hydrocarbons GP Co., L.L.C. and Black Diamond Minerals, LLC, which hold oil and natural gas properties in East Texas, North Louisiana and the Rocky Mountains; and

In February 2014, we repurchased net profits interests in the Terryville Complex from an affiliate of NGP for $63.4 million after customary adjustments. These net profits interests were originally sold to the NGP affiliate upon the completion of certain acquisitions in 2010 by WildHorse Resources.

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Our Equity Owners

Our principal stockholder is MRD Holdco, which is controlled by the Funds, which are three of the private equity funds managed by NGP. Upon completion of this offering, MRD Holdco, one of the selling stockholders in this offering, will own approximately 40% of our common stock (or approximately 38% if the underwriters option to purchase additional shares from the selling stockholders is exercised in full). The Funds also collectively indirectly own 50% of MEMP s incentive distribution rights. We are also a party to certain other agreements with MRD Holdco, the Funds and certain of their affiliates. For a description of these agreements, please read Certain Relationships and Related Party Transactions.

Upon completion of this offering, certain former management members of WildHorse Resources, some of which are selling stockholders in this offering along with MRD Holdco, will own approximately 18% of our common stock (or approximately 18% if the underwriters option to purchase additional shares from the selling stockholders is exercised in full). We are party to a services agreement with WildHorse Resources Management Company, LLC, a subsidiary of WildHorse Resources II, LLC. NGP and certain former management members of WildHorse Resources own WildHorse Resources II, LLC. For a description of this services agreement, please read Certain Relationships and Related Party Transactions.

Founded in 1988, NGP is a family of private equity investment funds, with cumulative committed capital of over $14.5 billion since inception, organized to make investments in the natural resources sector. NGP is part of the investment platform of NGP Energy Capital Management, a premier investment franchise in the natural resources industry, which together with its affiliates has managed over $17 billion in cumulative committed capital since inception.

Relationship with Memorial Production Partners LP

Through our ownership of its general partner, we control MEMP, a publicly traded limited partnership. In addition to the general partner interest, we also own 50% of MEMP s incentive distribution rights.

MEMP is engaged in the acquisition, exploitation, development and production of oil and natural gas properties in the United States, with assets consisting primarily of producing oil and natural gas properties that are located in East Texas/North Louisiana, the Rockies, South Texas, the Permian and offshore Southern California. Most of MEMP s properties are located in large, mature oil and natural gas reservoirs with well-known geologic characteristics and long-lived, predictable production profiles and modest capital requirements. As of December 31, 2013:

- MEMP s total estimated proved reserves were approximately 1,015 Bcfe, of which approximately 60% were natural gas and 61% were classified as proved developed reserves; and

- MEMP produced from 2,866 gross (1,663 net) producing wells across its properties, with an average working interest of 58%.

In accordance with MEMP s limited partnership agreement, incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of MEMP s available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The minimum quarterly distribution is $0.4750 ($1.90 on an annualized basis) per unit. MEMP GP owns 50% of the incentive distribution rights, which are freely transferable under the MEMP limited partnership agreement. We own 100% of the voting and economic interests in MEMP GP, and MEMP GP owns 50% of the MEMP incentive distribution rights. The incentive distribution rights are payable as follows:

If for any quarter:

MEMP has distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and

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- MEMP has distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, MEMP will distribute any additional available cash from operating surplus for that quarter among the unitholders and the general partner in the following manner:

- first, 99.9% to all unitholders, pro rata, and 0.1% to the holders of the incentive distribution rights (50% of which are owned by MEMP GP), until each unitholder receives a total of $0.54625 per unit for that quarter;

- second, 85.0% to all unitholders, pro rata, and 15.0% to the holders of the incentive distribution rights (50% of which are owned by MEMP GP), until each unitholder receives a total of $0.59375 per unit for that quarter;

- thereafter, 75.0% to all unitholders, pro rata, and 25.0% to the holders of the incentive distribution rights (50% of which are owned by MEMP GP).

Since December 2011, MEMP has increased its quarterly cash distribution from $0.4750 ($1.90 on an annualized basis) per unit to $0.5500 ($2.20 on an annualized basis) per unit, which is its most recently announced distribution.

We provide management, administrative, and operations personnel to MEMP under an omnibus agreement. Pursuant to that omnibus agreement, MEMP is required to reimburse us for all expenses incurred by us (or payments made on MEMP s behalf) in conjunction with our provision of general and administrative services to MEMP, including its public company expenses and an allocated portion of the salary and benefits of the executive officers of MEMP s general partner and our other employees who perform services for MEMP or on MEMP s behalf. Please read Certain Relationships and Related Party Transactions Omnibus Agreement for more information about the omnibus agreement.

We view our relationship with MEMP as a part of our strategic alternatives, and we believe that MEMP will be incentivized to acquire additional suitable assets from us and to pursue acquisitions jointly with us in the future. However, MEMP will regularly evaluate acquisitions and may elect to acquire properties in the future without offering us the opportunity to participate in those transactions. MEMP is free to act in a manner that is beneficial to its interests without regard to ours, which may include electing not to acquire additional assets from us. Although we believe MEMP will desire to acquire properties from us for purchase, MEMP will not have any obligation to acquire properties from us. If MEMP chooses not to acquire properties from us, then our ability to monetize our proved developed properties may be impaired, which could adversely affect our cash flow and net income.

Our Operations

Preparation of Reserve Estimates

Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. For a discussion of risks associated with reserve estimates, please read Risk Factors Risks Related to Our Business Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Evaluation and Review of Estimated Reserves. Our historical proved reserve estimates and MEMP s historical proved reserve estimates were prepared by NSAI, our independent petroleum engineers. The technical

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persons responsible for preparing our proved reserve estimates meet the requirements with regard to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. NSAI does not own an interest in any of our properties, nor is it employed by us on a contingent basis. A copy of NSAI s summary reserve report regarding our proved reserves as of December 31, 2013 is included as Appendix B-1 to this prospectus. A copy of NSAI s audit letter regarding the management report of our probable and possible reserves as of December 31, 2013 is included as Appendix B-2 to this prospectus. A copy of NSAI s summary reserve report regarding our proved reserves as of September 30, 2014 with respect to our Terryville Complex acreage is included in Appendix C to this prospectus. A copy of NSAI s summary reserve report regarding the MEMP proved reserves as of December 31, 2013 (the MEMP Reserve Report) is included as Exhibit 99.3 to the registration statement of which this prospectus forms a part.

Our historical probable and possible reserve estimates were prepared by us and audited by NSAI. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our estimated reserves and MEMP s proved reserves. Our technical team meets regularly with NSAI reserve engineers to review properties and discuss the assumptions and methods used in the reserve estimation process. We provide historical information to NSAI for our properties and MEMP s properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs.

Internal Engineers. John D. Williams is our technical person primarily responsible for liaison with and oversight of our and MEMP s third-party reserve engineers, NSAI, which prepared the reserve reports for our properties and MEMP s properties. Mr. Williams has been practicing petroleum engineering with us since March 2012. Mr. Williams is a Registered Professional Engineer in the State of Texas with over 17 years experience in the estimation and evaluation of reserves. From April 2005 to March 2012, he held various positions at Southwestern Energy Company, most recently as Reservoir Engineering Manager. From August 1998 to April 2005, he served in various capacities at Ryder Scott Company, which culminated in his serving as Vice President. Mr. Williams is a graduate of the University of Texas at Austin with a Bachelor of Science Degree in Petroleum Engineering and with a Master of Science Degree in Petroleum Engineering.

NSAI is an independent oil and natural gas consulting firm. No director, officer, or key employee of NSAI has any financial ownership in us, the Funds, or any of their respective affiliates. NSAI s compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported. NSAI has not performed other work for us, the Funds, or any of their respective affiliates that would affect its objectivity. The estimates of proved reserves presented in the NSAI reports were overseen by Mr. Justin S. Hamilton; Mr. David E. Nice; Mr. Richard B. Talley, Jr.; Mr. Philip S. (Scott) Frost; Mr. Joseph J. Spellman; Mr. Eric J. Stevens; Mr. Craig H. Adams; Mr. Nathan C. Shahan; Mr. J. Carter Henson, Jr., Mr. Allen E. Evans, Jr. and Mr. William J. Knights.

Justin Hamilton has been practicing consulting petroleum engineering at NSAI since 2004. Mr. Hamilton is a Licensed Professional Engineer in the State of Texas (License No. 104999) and has over 13 years of practical experience in petroleum engineering, with over 13 years of experience in the estimation and evaluation of reserves. He graduated from Brigham Young University in 2000 with a B.S. in mechanical engineering and from the University of Texas in 2007 with an M.B.A.

David Nice has been practicing consulting petroleum geology at NSAI since 1998. Mr. Nice is a Licensed Professional Geoscientist in the State of Texas (License No. 346) and has over 28 years of practical experience in petroleum geosciences, with over 15 years of experience in the estimation and evaluation of reserves. He graduated from University of Wyoming in 1982 with a B.S. in geology and in 1985 with an M.S. in geology.

Richard Talley has been practicing consulting petroleum engineering at NSAI since 2004. Mr. Talley is a Licensed Professional Engineer in the State of Texas (License No. 102425) and in the State of Louisiana

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(License No. 36998) and has over 15 years of practical experience in petroleum engineering, with over 9 years of experience in the estimation and evaluation of reserves. He graduated from University of Oklahoma in 1998 with a B.S. in mechanical engineering and from Tulane University in 2001 with an M.B.A.

Scott Frost has been practicing consulting petroleum engineering at NSAI since 1984. Mr. Frost is a Licensed Professional Engineer in the State of Texas (License No. 88738) and has over 30 years of practical experience in petroleum engineering, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Vanderbilt University in 1979 with a B.E. in mechanical engineering and from Tulane University in 1984 with an M.B.A.

Joseph Spellman has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Spellman is a Licensed Professional Engineer in the State of Texas (License No. 73709) and has over 30 years of practical experience in petroleum engineering, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from University of Wisconsin-Platteville in 1980 with a B.S. in civil engineering.

Eric Stevens has been practicing consulting petroleum engineering at NSAI since 2007. Mr. Stevens is a Licensed Professional Engineer in the State of Texas (License No. 102415) and has over 11 years of practical experience in petroleum engineering, with over 11 years of experience in the estimation and evaluation of reserves. He graduated from Brigham Young University in 2002 with a B.S. in mechanical engineering.

Craig Adams has been practicing consulting petroleum engineering at NSAI since 1997. Mr. Adams is a Licensed Professional Engineer in the State of Texas (License No. 68137) and has over 29 years of practical experience in petroleum engineering, with over 17 years of experience in the estimation and evaluation of reserves. He graduated from Texas Tech University in 1985 with a B.S. in petroleum engineering.

Nathan Shahan has been practicing consulting petroleum engineering at NSAI since 2007. Mr. Shahan is a Licensed Professional Engineer in the State of Texas (License No. 102389) and has over 12 years of practical experience in petroleum engineering, with over 7 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 2002 with a B.S. in petroleum engineering and in 2007 with a M.E. in petroleum engineering.

Allen Evans has been practicing consulting petroleum geology at NSAI since 1996. Mr. Evans is a Licensed Professional Geoscientist in the State of Texas (License No. 1286) and has over 30 years of practical experience in petroleum geosciences, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Old Dominion University in 1981 with a B.S. in geology and in 1987 with a M.S. in geology.

Carter Henson has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Henson is a Licensed Professional Engineer in the State of Texas (License No. 73964) and has over 30 years of practical experience in petroleum engineering, with over 25 years of experience in the estimation and evaluation of reserves. He graduated from Rice University in 1981 with a B.S. in mechanical engineering.

William Knights has been practicing consulting petroleum geology at NSAI since 1991. Mr. Knights is a Licensed Professional Geoscientist in the State of Texas (License No. 1532) and has over 30 years of practical experience in petroleum geosciences, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Texas Christian University in 1981 with a B.S. in geology and in 1984 with a M.S. in geology.

All eleven technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; all eleven are proficient in applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

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Estimation of Proved Reserves. Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a high degree of confidence that the quantities will be recovered. All of our proved reserves and MEMP s proved reserves as of December 31, 2013 and September 30, 2014 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

To estimate economically recoverable proved reserves and related future net cash flows, NSAI considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

Estimation of Probable and Possible Reserves. Estimates of probable reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate of those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of

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structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Estimates of possible reserves are also inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserve where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir. Possible reserves also include incremental quantities associated with a greater percentage of recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

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Estimated Reserves

The table below identifies our reserves as of December 31, 2013 per our reserve report for our three areas:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MMcfe)
Proved Developed				
Terryville Complex	2,933	220,588	12,050	310,484
East Texas	165	40,435	1,678	51,492
Rockies	306	2,774	176	5,665
Total Proved Developed	**3,403**	**263,797**	**13,905**	**367,641**
Proved Undeveloped				
Terryville Complex	7,585	448,123	23,402	634,049
East Texas	323	90,334	5,270	123,887
Rockies				
Total Proved Undeveloped	**7,908**	**538,457**	**28,672**	**757,936**
Total Proved				
Terryville Complex	10,518	668,711	35,452	944,533
East Texas	487	130,769	6,948	175,379
Rockies	306	2,774	176	5,665
Total Proved Reserves	**11,311**	**802,254**	**42,577**	**1,125,577**
Probable(1)				
Terryville Complex	10,041	453,902	29,056	688,486
East Texas	285	79,765	4,653	109,392
Rockies	153	1,519		2,439
Total Probable Reserves	**10,480**	**535,185**	**33,709**	**800,317**
Possible(1)				
Terryville Complex	36,098	1,031,112	65,869	1,642,911
East Texas	172	48,299	2,817	66,239
Rockies	106	1,128		1,762
Total Possible Reserves	**36,376**	**1,080,539**	**68,686**	**1,710,913**

(1) Substantially all of our estimated probable and possible reserves are classified as undeveloped.

Proved Undeveloped Reserves

As of December 31, 2013, we had 758 Bcfe of proved undeveloped reserves, comprised of 8 MMBbls of oil, 538 Bcf of natural gas and 29 MMBbls of NGLs. None of our PUDs as of December 31, 2013 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUDs. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

Changes in PUDs that occurred during 2013 were due to:

- Reclassifications of 20.2 Bcfe into proved developed reserves for implementation of drilling projects; and

- Reduction of 5.2 Bcfe after giving effect to 66.9 Bcfe of additions from the Terryville Complex due to proving up additional drilling locations.

During the year ended December 31, 2013, we spent $69.0 million to convert PUDs to proved developed reserves. As of December 31, 2013 per our reserve report, future development costs relating to the development of PUDs for the years 2014, 2015, 2016, 2017 and 2018 are estimated at approximately $248 million, $358 million, $282 million, $264 million and $160 million, respectively, to capture the balance of drilling the PUD reserves within a five-year timeframe. Approximately 84%, or $1.1 billion, of the future development costs over the next five years are related to development of PUD reserves in the Terryville Complex. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in the upcoming years. All of our PUD locations are scheduled to be drilled prior to the end of December 31, 2018. Based on our current expectations of its cash flows, we believe that we can fund the drilling of our current PUD inventory and our expansions in the next five years from our cash flow from operations.

Production, Revenues and Price History

The following table sets forth information regarding our production, revenues and realized prices and production costs for the nine months ended September 30, 2014 and for the years ended December 31, 2013 and 2012.

	Nine months ended September 30, 2014			
	Terryville	East Texas	Rockies	Total
Production Volumes:				
Oil (MBbls)	560	35	93	688
NGLs (MBbls)	1,300	280	31	1,611
Natural gas (MMcf)	36,583	5,604	888	43,075
Total (MMcfe)	47,750	7,495	1,625	56,870
Average net production (MMcfe/d)	174.9	27.5	6.0	208.3
Average sales price:				
Oil (per Bbl)	$ 97.82	$ 93.09	$ 88.86	$ 96.37
NGL (per Bbl)	45.17	27.62	32.52	41.87
Natural gas (per Mcf)	3.84	4.17	3.60	3.87
Total (Mcfe)	$ 5.32	$ 4.59	$ 7.67	$ 5.30
Average unit costs per Mcfe:				
Lease operating expense	$ 0.24	$ 0.83	$ 0.74	$ 0.33

	Year Ended December 31, 2013			
	Terryville	East Texas	Rockies	Total
Production Volumes:				
Oil (MBbls)	475	165	25	665
NGLs (MBbls)	1,243	177	37	1,457
Natural gas (MMcf)	27,398	6,249	445	34,092
Total (Mmcfe)	37,705	8,297	817	46,819
Average net production (Mmcfe/d)	103.3	22.8	2.2	128.3
Average Sales Price (Excluding Commodity Derivatives):				
Oil (per Bbl)	$ 100.57	$ 102.06	$ 95.78	$ 100.76
NGL (Per Bbl)	$ 37.69	$ 31.33	$ 40.68	$ 36.99
Natural Gas (per Mcf)	$ 3.10	$ 3.79	$ 2.91	$ 3.22

Total (per Mcfe)	$ 4.76	$ 5.54	$ 6.39	$ 4.93
Average Unit Costs per Mcfe:				
Lease operating expense	$ 0.33	$ 1.24	$ 1.91	$ 0.53

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	Year Ended December 31, 2012			
	Terryville	East Texas	Rockies	Total
Production Volumes:				
Oil (MBbls)	273	67	29	369
NGLs (MBbls)	702	85	111	898
Natural gas (MMcf)	14,028	8,917	1,185	24,130
Total (Mmcfe)	19,874	9,832	2,025	31,731
Average net production (Mmcfe/d)	54.3	26.9	5.5	86.7
Average Sales Price (Excluding Commodity Derivatives):				
Oil (per Bbl)	$ 95.78	$ 97.98	$ 88.05	$ 95.56
NGL (Per Bbl)	$ 40.52	$ 39.08	$ 43.71	$ 40.78
Natural Gas (per Mcf)	$ 2.53	$ 3.13	$ 2.32	$ 2.74
Total (per Mcfe)	$ 4.53	$ 3.84	$ 5.02	$ 4.35
Average Unit Costs per Mcfe:				
Lease operating expense	$ 0.61	$ 0.99	$ 1.24	$ 0.77

Productive Wells

The following table sets forth certain information regarding productive wells in each of our areas at December 31, 2013.

Area	Gross	Net	Operated
Terryville Complex	626	396	499
East Texas	123	92	95
Rockies	146	20	1
Total	895	508	595

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2013.

	Developed Acres		Undeveloped Acres		Total Acreage			
	Gross	Net	Gross	Net	Gross	Net	HBP	WI
Terryville Complex	106,374	73,875	24,372	22,858	130,746	96,733	76%	74%
East Texas	37,109	30,335	17,228	12,559	54,337	42,894	71%	79%
Rockies	5,659	3,147	156,716	63,044	162,375	66,191	5%	41%
Total	**149,142**	**107,357**	**198,316**	**98,461**	**347,458**	**205,818**	**52%**	**59%**
Terryville Complex Core(1)	**35,749**	**28,743**	**24,292**	**22,778**	**60,041**	**51,552**	**56%**	**86%**

(1) The substantial majority of what we believe to be the Terryville Complex Core is located in Lincoln Parish, Louisiana and is where we will focus the majority of our future development.

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Undeveloped Acreage Expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2013 that will expire over the next three years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates. There are no reserves attributable to our expiring acreage.

	2014		2015		2016	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Terryville Complex	2,407	2,180	2,487	2,390	3,633	3,420
East Texas	5,212	2,606	2,027	748		
Rockies	3,206	2,199	15,564	8,878	27,582	17,455
Total	10,825	6,985	20,078	12,015	31,215	20,875

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2013, 2012 and 2011. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. At December 31, 2013, 10 gross (9.2 net) wells were in various stages of completion.

	Year Ended December 31,					
	2013		2012		2011	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development wells:						
Productive	22.0	13.3	11.0	10.2	4.0	3.9
Dry						
Total development wells	22.0	13.3	11.0	10.2	4.0	3.9
Exploratory wells:						
Productive	9.0	8.0	7.0	5.6	27.0	9.4
Dry					3.0	1.5
Total exploratory wells	9.0	8.0	7.0	5.6	30.0	10.9
Total wells drilled	31.0	21.3	18.0	15.8	34.0	14.8

Drilling Locations

1,171 of our 1,582 gross horizontal locations as of December 31, 2013 are attributable to acreage that is currently held by production and approximately 9% are attributable to proved undeveloped reserves as of December 31, 2013. In making these assessments, we include properties in which we hold operated and non-operated interests, as well as redevelopment opportunities. Once we have identified acreage that is prospective for the targeted formations, well placement is determined primarily by the regulatory spacing rules prescribed by the governing body in each of our operating areas.

Our 1,582 gross horizontal drilling locations include 145 locations in the proved category, 209 in the probable category, and 485 in the possible category as evaluated or audited by NSAI, our third party engineers. The additional 743 gross horizontal drilling locations are locations that have been identified by our management team. We identified those additional locations using the same methodology as those locations to which probable and possible reserves are attributed by using existing geologic and engineering data from vertical production and seismic data. Of those 743 gross horizontal drilling locations, 321 lie within the geographic areas to which probable and possible reserves are attributed and are based on assumed well spacing of 137 acres versus our audited well spacing assumption of 280 acres. We believe that our 137-acre spacing assumptions are supported by existing production results. We are currently drilling multiple 137-acre spaced horizontal wells (and we have drilled horizontal wells using that spacing that are currently producing) in the same geographic area where we have identified all of our management locations. With respect to the 321 management locations within the areas to which proved, probable or possible reserves are attributed, we have received all necessary state and local approvals to drill at 18 of those locations. We have not encountered any, and are aware of no, regulatory constraints or field rules preventing us from obtaining new permits on all of our acreage using our assumed spacing, and we believe that the remaining 303 locations will also receive all necessary approvals upon application.

The remaining 422 identified gross horizontal drilling locations, all of which are also based upon 137- acre spacing, are within geographic areas to which proved, probable or possible reserves are not attributed, but nonetheless are locations that we have specifically identified based on our evaluation of applicable geologic and engineering data accrued over our multi-year historical drilling activities in the surrounding area. Of those 422 locations, we have received all necessary state and local approvals to drill at three of those locations. We have not encountered any, and are aware of no, regulatory constraints or field rules preventing us from obtaining new permits on all of our acreage using our assumed spacing; accordingly, we believe that the remaining 419 locations will also receive all necessary approvals upon application. We believe that area seismic data, as well as information gathered from the results of our existing 275 vertical and 46 horizontal wells throughout the field, support the existence of at least ten stacked pay zones across the Terryville Complex.

In evaluating and determining those locations, we also considered the availability of local infrastructure, drilling support assets and easement restrictions and state and local regulations. The locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results and other factors, and may differ from the locations currently identified. For a discussion of the risks associated with our drilling program, see Risk Factors Risks Related to Our Business Our identified drilling locations, which are scheduled out over many years, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

MEMP

The following table summarizes information about MEMP s proved oil and natural gas reserves by geographic region as of December 31, 2013 and its average net production for the nine months ended September 30, 2014:

	Estimated Total Proved Reserves					Average Net Daily Production (MMcfe/d)
	Total (Bcfe)	% Gas	% Oil & NGLs	% Developed	Standardized Measure (in millions)(1)	
East Texas/North Louisiana	598	69%	31%	54%	$ 688	117
Permian Basin	108	8%	92%	45%	362	13
California	86	0%	100%	70%	344	10
Rockies	61	83%	17%	84%	78	22
South Texas	162	85%	15%	82%	137	28
Total	1,015	60%	40%	61%	$ 1,609	190

(1) Standardized measure is calculated in accordance with Accounting Standards Codification, or ASC, Topic 932, Extractive Activities Oil and Gas. Because MEMP is a limited partnership, it is generally not subject to federal or state income taxes and thus makes no provision for federal or state income taxes in the calculation of its standardized measure. Standardized measure does not give effect to commodity derivative contracts.

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Estimated Proved Reserves

The following table presents the estimated net proved oil and natural gas reserves attributable to MEMP s properties and the standardized measure amounts associated with the estimated proved reserves attributable to MEMP s properties as of December 31, 2013, based on MEMP s reserve report.

	Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MMcfe)
Estimated Proved Reserves				
Total Proved Developed	22,265	387,548	15,959	616,893
Total Proved Undeveloped	16,884	219,591	12,887	398,212
Total Proved Reserves	39,149	607,139	28,846	1,015,105

Development of Proved Undeveloped Reserves

As of December 31, 2013, MEMP had 398,212 MMcfe of proved undeveloped reserves, comprised of 16,884 MBbls of oil, 219,591 MMcf of natural gas and 12,887 MBbls of NGLs. None of MEMP s PUDs as of December 31, 2013 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUDs. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

Changes in PUDs that occurred during 2013 were due to:

- Reclassifications of 69.5 Bcfe into proved developed reserves for implementation of drilling projects; and

- Increases of 72.3 Bcfe primarily due to reserve additions and price revisions.

During the year ended December 31, 2013, MEMP spent $103.4 million to convert PUDs to proved developed reserves. As of December 31, 2013 per the MEMP Reserve Report, future development costs relating to the development of PUDs for the years 2014, 2015, 2016, 2017 and 2018 are estimated at approximately $185 million, $178 million, $179 million, $72 million and $7 million, respectively, to capture the balance of drilling the PUD reserves within a five-year timeframe. As MEMP continues to develop its properties and have more well production and completion data, MEMP believes it will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in the upcoming years. All of MEMP s PUD locations are scheduled to be drilled prior to the end of December 31, 2018. Based on MEMP s current expectations of its cash flows, MEMP believes that it can fund the drilling of its current PUD inventory and its expansions in the next five years from its cash flow from operations.

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Production, Revenue and Price History

The following tables summarize MEMP s average net production, average sales prices by product and average production costs for the nine months ended September 30, 2014 and for the years ended December 31, 2013 and 2012, respectively:

	Nine months ended September 30, 2014	Year Ended December 31, 2013	2012
Production Volumes:			
Oil (MBbls)	2,056	1,764	1,519
NGLs (MBbls)	1,498	1,632	745
Natural gas (MMcf)	30,625	35,924	29,744
Total (Mmcfe)	51,946	56,303	43,329
Average net production (Mmcfe/d)	190.3	154.3	118.4
Average Sales Price (Excluding Commodity Derivatives):			
Oil (per Bbl)	$ 93.45	$ 96.98	$ 95.54
NGL (Per Bbl)	$ 32.69	$ 31.38	$ 35.75
Natural Gas (per Mcf)	$ 4.16	$ 3.31	$ 2.82
Total (per Mcfe)	$ 7.09	$ 6.06	$ 5.90
Average Unit Costs per Mcfe:			
Lease operating expense	$ 1.80	$ 1.58	$ 1.85

Productive Wells

Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which MEMP owns an interest, and net wells are the sum of MEMP s fractional working interests owned in gross wells. The following table sets forth information relating to the productive wells in which MEMP owned a working interest as of December 31, 2013.

	Oil		Natural Gas	
	Gross	**Net**	**Gross**	**Net**
Operated(1)	489	441	1,432	1,063
Non-operated	43	8	902	151
Total	532	449	2,334	1,214

(1) Includes wells operated by the Company on MEMP s behalf.

Developed Acreage

Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2013, substantially all of MEMP s leasehold acreage was held by production. The following table sets forth information as of December 31, 2013 relating to MEMP s leasehold acreage.

	Developed Acreage(1)	
Region	**Gross(2)**	**Net(3)**
East Texas/North Louisiana	142,118	55,593
Permian	33,832	24,675
Rockies	133,664	48,910
South Texas	85,027	70,629
Total	394,641	199,807

(1) Developed acres are acres spaced or assigned to productive wells or wells capable of production.

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(2) A gross acre is an acre in which MEMP owns a working interest. The number of gross acres is the total number of acres in which MEMP owns a working interest.
(3) A net acre is deemed to exist when the sum of MEMP s fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Undeveloped Acreage

The following table sets forth information as of December 31, 2013 relating to MEMP s undeveloped leasehold acreage.

Region	Undeveloped Acreage Gross(1)	Net(2)
East Texas/North Louisiana	14,385	5,254
Permian	16,717	13,599
Rockies	73,422	50,802
South Texas	1,658	1,658
Total	106,182	71,313

(1) A gross acre is an acre in which MEMP owns a working interest. The number of gross acres is the total number of acres in which MEMP owns a working interest.
(2) A net acre is deemed to exist when the sum of MEMP s fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Drilling Activities

MEMP s drilling activities consist entirely of development wells. The following table sets forth information with respect to wells drilled and completed by MEMP, its predecessor, or the previous owners during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Year Ended December 31, 2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	45.0	32.6	38.0	24.4	14.0	10.7
Dry			1.0	1.0	1.0	1.0
Exploratory wells:						
Productive						
Dry						
Total wells:						
Productive	45.0	32.6	38.0	24.4	14.0	10.7
Dry			1.0	1.0	1.0	1.0
Total	45.0	32.6	39.0	25.4	15.0	11.7

For purposes of the table above, MEMP s predecessor refers collectively to (a) BlueStone and its wholly-owned subsidiaries and certain oil and natural gas properties owned by Classic Hydrocarbons Holdings, L.P. for periods prior to the closing of MEMP s initial public offering on December 14, 2011 and (b) for periods after April 8, 2011 through the closing of MEMP s initial public offering, certain oil and natural gas properties owned by WHT Energy Partners LLC. MEMP s previous owners refers collectively to (a) certain oil and natural gas properties that MEMP acquired from MRD LLC in April and May 2012 for periods after common control commenced through their respective acquisition dates and (b) Rise Energy Operating, LLC and its wholly-owned subsidiaries (except for Rise Energy Operating, Inc.) from February 3, 2009 (inception) through December 11, 2012.

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Delivery Commitments

MEMP has no commitments to deliver a fixed and determinable quantity of our oil or natural gas production in the near future under our existing contracts.

Marketing and Major Customers

We market the majority of production from properties we and MEMP operate for both our account and the account of the other working interest owners in our operated properties. We sell substantially all of our production to a variety of purchasers under contracts ranging from one month to several years, all at market prices. We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. During the year ended December 31, 2013, Energy Transfer Equity, L.P. and subsidiaries accounted for 77% of our revenues and Phillips 66 accounted for 15% of MEMP s revenues. If we were to lose any one of our customers, the loss could temporarily delay production and sale of a portion of our oil and natural gas in the related producing region. If we were to lose any single customer, we believe we could identify a substitute customer to purchase the impacted production volumes.

Title to Properties

We believe that we and MEMP have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations under natural gas leases, or net profits interests.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties and MEMP s properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 12.5% to 25%, resulting in a net revenue interest to us generally ranging from 87.5% to 75%.

Seasonality

Demand for oil and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations or MEMP s operations.

Competition

The oil and natural gas industry is intensely competitive, and we and MEMP compete with other companies in our industry that have greater resources than we do, especially in our focus areas. Many of these companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and exploratory locations or define, evaluate, bid for and purchase a greater number of properties and locations than our financial or human resources permit, and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory locations and producing natural gas properties.

Hydraulic Fracturing

We and MEMP use hydraulic fracturing as a means to maximize the productivity of almost every well that we drill and complete. Hydraulic fracturing is a necessary part of the completion process because our properties are dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. Nearly all of our proved non-producing and proved undeveloped reserves associated with future drilling, recompletion, and refracture stimulation projects, or approximately 71.3% of our total estimated proved reserves as of December 31, 2013 and approximately 37.6% of MEMP s total estimated proved reserves as of December 31, 2013, require hydraulic fracturing.

We have and continue to follow applicable industry standard practices and legal requirements for groundwater protection in our and MEMP s operations which are subject to supervision by state and federal regulators (including the Bureau of Land Management on federal acreage). These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by regulatory agencies, and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design essentially eliminates a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval.

Injection rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations would be shut down immediately if an abrupt change occurred to the injection pressure or annular pressure.

Certain state regulations require disclosure of the components in the solutions used in hydraulic fracturing operations. Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand. The remainder of the constituents in the fracturing fluid are managed and used in accordance with applicable requirements.

Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it in a way that minimizes the impact to nearby surface water by disposing into approved disposal or injection wells. We currently do not discharge water to the surface.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read Regulation of Environmental and Occupational Health and Safety Matters Hydraulic Fracturing.

Regulation of the Oil and Natural Gas Industry

Our and MEMP s operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the natural gas industry are regularly considered by Congress, the states, FERC, and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we and MEMP are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Oil and Natural Gas

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we and MEMP own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. We own interests in properties located onshore in different U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and natural gas properties and establishment of maximum rates of production from oil and natural gas wells. Some states have the power to prorate production to the market demand for oil and natural gas. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Environmental and Occupational Health and Safety Matters

Our and MEMP s operations are subject to numerous stringent federal, state and local statutes and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (EPA), issue regulations, which often require difficult and costly

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compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for failure to comply. These laws and regulations may, among other things, require the acquisition of a permit before drilling commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines; govern the sourcing and disposal of water used in the drilling, completion and production process; restrict the way we handle or dispose of our wastes or of naturally occurring radioactive materials generated by our operations; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; require some form of remedial action to prevent or mitigate pollution from current or former operations such as plugging abandoned wells or closing earthen pits; result in the suspension or revocation of necessary permits, licenses and authorizations; require that additional pollution controls be installed; and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. Changes in environmental laws and regulations occur frequently, and to the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business and prospects, as well as the oil and natural gas industry in general, could be materially adversely affected.

Hazardous Substance and Waste Handling

Our and MEMP s operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, referred to as CERCLA or the Superfund law, and comparable state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons deemed responsible parties. These persons include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release or disposal of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Despite the petroleum exclusion of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. Also, comparable state statutes may not contain a similar exemption for petroleum. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties.

The Oil Pollution Act of 1990 (the OPA) is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on responsible parties for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A responsible party includes the owner or operator of an onshore facility. The OPA establishes a liability limit for onshore facilities of $350 million per spill. These liability limits may not apply if: a spill is caused by a party s gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or a party fails to report a spill or to cooperate fully in a clean-up. We are also subject to analogous state statutes that impose liabilities with respect to oil spills.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act (RCRA), as amended, and comparable state statutes. Although RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA s hazardous waste regulations. It is possible, however, that these wastes, which could include wastes currently generated during our operations, could be designated as hazardous wastes in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and gas exploration and production wastes as hazardous wastes. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

It is possible that our oil and natural gas operations may require us to manage naturally occurring radioactive materials, or NORM. NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes in contact with crude oil and natural gas production and processing streams. Some states have enacted regulations governing the handling, treatment, storage and disposal of NORM.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we and MEMP are in substantial compliance with the requirements of CERCLA, RCRA, OPA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water and Other Waste Discharges and Spills

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, the Safe Drinking Water Act (SDWA), the OPA and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other gas and oil wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs.

These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and the underground injection of fluids and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as SPCC plans, in connection with on-site storage of significant quantities of oil. We and MEMP maintain all required discharge permits necessary to conduct our operations, and we believe we and MEMP are in substantial compliance with their terms.

Hydraulic Fracturing

We and MEMP use hydraulic fracturing extensively in our operations. Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from low permeability subsurface rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. While hydraulic fracturing has historically been regulated by state oil and natural gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. For example, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the SDWA involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in late 2014. In addition, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014. In addition, Congress has from time to time considered legislation to amend the SDWA, including legislation that would repeal the exemption for hydraulic fracturing from the definition of underground injection and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process. Also, in the near future we may be subject to regulations that restrict our ability to discharge water produced as part of our production operations, and the ability to use injection wells as a disposal option not only will depend on federal or state regulations but also on whether available injection wells have sufficient storage capacities. The EPA is currently developing effluent limitation guidelines that may impose federal pre-treatment standards on oil and gas operators transporting wastewater associated with hydraulic fracturing activities to publicly owned treatment works for disposal. The EPA plans to propose such standards by late 2014. In addition, in May 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed rule would require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. The Bureau of Land Management plans to issue a final rule in 2014.

Further, in April 2012, the EPA released final rules that subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the new source performance standards (NSPS) and the National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The rules include NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or green completions on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules could require a number of modifications to our operations including the installation of new equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The

EPA intends to issue revised rules that are likely to be responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rules addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On July 1, 2014, the EPA announced proposed amendments and clarifications to the NSPS standards. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Several states have adopted, or are considering adopting, regulations requiring the disclosure of the chemicals used in hydraulic fracturing and/or otherwise impose additional requirements for hydraulic fracturing activities. For example, in October 2011, the Louisiana Department of Natural Resources adopted new rules requiring the public disclosure of the composition and volume of fracturing fluids used in hydraulic fracturing operations. Also, Texas requires oil and natural gas operators to disclose to the Texas Railroad Commission and the public the chemicals used in the hydraulic fracturing process, as well as the total volume of water used. On October 28, 2014, the Texas Railroad Commission adopted disposal well rule amendments designed, amongst other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments also clarify the Commission s authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The disposal well rule amendments become effective November 17, 2014. Furthermore, in May 2013, the Texas Railroad Commission issued a well integrity rule, which updates the requirements for drilling, putting pipe down, and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices, which could lead to increased regulation. For example, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has also commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012, and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by late 2014. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have adversely impacted drinking water supplies, use of surface water, and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing, and any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Air Emissions

The federal Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in April 2012, the EPA released final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the NSPS and NESHAPS programs. The rules include NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or green completions on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules could require a number of modifications to our operations including the installation of new equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that are likely to be responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rules addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On July 1, 2014, the EPA announced proposed amendments and clarifications to the NSPS standards.

We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing air emission related issues, which may have a material adverse effect on our operations. Obtaining permits also has the potential to delay the development of oil and natural gas projects. We believe that we and MEMP currently are in substantial compliance with all air emissions regulations and that we and MEMP hold all necessary and valid construction and operating permits for our current operations.

Regulation of Greenhouse Gas Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases (GHGs) present an endangerment to public health and the environment, in May 2010, the EPA adopted regulations under existing provisions of the federal Clean Air Act (CAA) that, among other things, established Prevention of

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Significant Deterioration (PSD) construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. The so-called Tailoring Rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the Clean Air Act. On June 23, 2014, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD or Title V programs. The EPA has announced that it is currently evaluating the decision and awaiting further action by the courts, and that it will provide relevant guidance on GHG permitting requirements.

In September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. In addition, the Obama Administration has announced in its Climate Action Plan that it intends to adopt additional regulations to reduce emissions of GHGs in the coming years, possibly including further restrictions on emissions of methane from oil and natural gas facilities.

Restrictions on GHG emissions that may be imposed in various states could adversely affect the oil and natural gas industry. Any GHG regulation could increase our costs of compliance by potentially delaying the receipt of permits and other regulatory approvals; requiring us to monitor emissions, install additional equipment or modify facilities to reduce GHG and other emissions; purchase emission credits; and utilize electric driven compression at facilities to obtain regulatory permits and approvals in a timely manner. While we are subject to certain federal GHG monitoring and reporting requirements, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Occupational Safety and Health Act

We are also subject to the requirements of the OSHA and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA s hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our and MEMP s operations are in substantial compliance with the OSHA requirements.

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National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an environmental assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This environmental impact assessment process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Endangered Species Act

The federal Endangered Species Act (ESA) and analogous state statutes restrict activities that may adversely affect endangered and threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The designation of previously unidentified endangered or threatened species in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans. Numerous species have been listed or proposed for protected status in areas in which we currently, or could in the future, undertake operations. For instance, the American burying beetle and the lesser prairie chicken both have habitat in some areas where we operate. The U.S. Fish and Wildlife Service (FWS) identified the lesser prairie chicken, which inhabits portions of Colorado, Kansas, Nebraska, New Mexico, Oklahoma and Texas, as candidate for listing in 1998 and has listed it as threatened in March 2014. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies, pursuant to which such parties agreed to take steps to protect the lesser prairie chicken s habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken s habitat. The threatened species status of the lesser prairie chicken is currently subject to a pending lawsuit by at least three states. The lawsuit challenges FWS recent classification of the lesser prairie chicken. The presence of protected species in areas where we operate could impair our ability to timely complete or carry out those operations, lose leaseholds as we may not be permitted to timely commence drilling operations, cause us to incur increased costs arising from species protection measures, and, consequently, adversely affect our results of operations and financial position.

Summary

In summary, we believe we and MEMP are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2012 or 2013.

Employees

As of September 30, 2014, we had 460 full-time employees. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Our Offices

Our executive offices are located at 500 Dallas St., Suite 1800, Houston, TX 77002, and the phone number at this address is (713) 588-8300.

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Legal Proceedings

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we have insurance coverage. As of the date hereof, neither we nor MEMP are party to any material legal proceedings.

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MANAGEMENT

Directors and Executive Officers

The following table provides information regarding our current executive officers and directors as of November 1, 2014.

Name	Age	Position
Tony R. Weber	52	Chairman
John A. Weinzierl	46	Chief Executive Officer and Director
William J. Scarff	59	President
Andrew J. Cozby	47	Senior Vice President and Chief Financial Officer
Larry R. Forney	57	Senior Vice President and Chief Operating Officer
Kyle N. Roane	35	Senior Vice President, General Counsel and Corporate Secretary
Gregory M. Robbins	35	Senior Vice President, Corporate Development
Dennis G. Venghaus	33	Chief Accounting Officer
Scott A. Gieselman	51	Director
Kenneth A. Hersh	51	Director
Robert A. Innamorati	67	Director
Carol L. O Neill	51	Director
Pat Wood, III	52	Director

Set forth below is a description of the backgrounds of our executive officers and directors.

Tony R. Weber has served as Chairman of our Board since our formation and as a member of MRD LLC s board of managers from September 2011 to June 2014 and MEMP GP s board of directors since September 2011. Mr. Weber currently serves as Managing Partner and Chief Operating Officer for NGP. Prior to joining NGP in December 2003, Mr. Weber was the Chief Financial Officer of Merit Energy Company from April 1998 to December 2003. Prior to that, he was Senior Vice President and Manager of Union Bank of California s Energy Division in Dallas, Texas from 1987 to 1998. In his role at NGP, Mr. Weber serves on numerous private company boards as well as industry groups, IPAA Capital Markets Committee and Dallas Wildcat Committee. He currently serves on the Dean s Council of the Mays Business School at Texas A&M University and was a founding member of the Mays Business Fellows Program.

The Board believes that Mr. Weber s extensive corporate finance, banking and private equity experience bring substantial leadership skill and experience to the Board.

John A. Weinzierl has served as our Chief Executive Officer since our formation, and the Chief Executive Officer of MRD LLC from January 2014 to June 2014 and the Chief Executive Officer and Chairman of MEMP GP since January 2014. Previously, Mr. Weinzierl served as President and Chief Executive Officer of MRD LLC and President, Chief Executive Officer and Chairman of MEMP GP since April 2011. Prior to the completion of the Partnership s initial public offering in December 2011, Mr. Weinzierl was a managing director and operating partner of NGP from December 2010. From July 1999 to December 2010, Mr. Weinzierl worked in various positions at NGP, where he became a managing director in December 2004. Mr. Weinzierl was appointed a venture partner of NGP from February 2012 to February 2013. From October 2006 until November 2011, Mr. Weinzierl was a director of Eagle Rock Energy G&P, LLC, the indirect general partner of Eagle Rock Energy Partners, L.P., a (i) natural gas gathering, processing and transportation company and (ii) developer of oil and natural gas properties, where he also served on the compensation committee. Mr. Weinzierl is a registered professional engineer in Texas.

The Board believes Mr. Weinzierl s degree and experience in petroleum engineering and his M.B.A. education, as well as his investment and business expertise honed at NGP, bring valuable strategic, managerial and analytical skills to the Board and us.

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William J. Scarff has served as our President since our formation, and the President of MRD LLC from January 2014 to June 2014 and MEMP GP since January 2014. From 2000 through January 2014, Mr. Scarff has served as President and Chief Executive Officer of several private exploration and production companies sponsored by Natural Gas Partners. Since October 2010, Mr. Scarff has served as President and Chief Executive Officer of Propel Energy, LLC. Prior to that, he was President and Chief Executive Officer of Seismic Ventures, Inc. from 2006 to 2009. Since February 2005, Mr. Scarff has served as President and Chief Executive Officer of Proton Operating Company, LLC and from 1999 to 2005, he was President and Chief Executive Officer of Proton Energy, LLC and its affiliates. From 1978 to 1999, Mr. Scarff held a variety of positions of increasing responsibility in Marathon Oil Company, Anadarko Production Company, Burlington Resources, Texas Meridian Resource Corporation and Hilcorp Energy Company.

Andrew J. Cozby has served as our Senior Vice President and Chief Financial Officer since November 2014, our Vice President and Chief Financial Officer from April 2014 to November 2014, the Vice President and Chief Financial Officer of MEMP GP since February 2012 and the Vice President, Finance of MRD LLC from April 2011 to June 2014. From February 2011 to April 2011, Mr. Cozby served as Senior Vice President and Chief Financial Officer of Energy Maintenance Services (EMS Global). Prior to that, he was Chief Financial Officer of Greystone Oil & Gas LLP and Greystone Drilling LP from May 2006 to December 2010. From 2000 to May 2006, Mr. Cozby was Director of Finance for Enterprise Products Partners LP and held various corporate finance positions with its affiliates GulfTerra Energy Partners, LP and El Paso Energy Partners, LP. Prior to that, Mr. Cozby held positions with J.P. Morgan from 1998 to 2000.

Larry R. Forney has served as our Senior Vice President and Chief Operating Officer since November 2014, our Vice President and Chief Operating Officer from June 2014 to November 2014, our Vice President, Operations from April 2014 to June 2014, the Vice President and Chief Operating Officer of MEMP GP since January 2013 and the Vice President, Operations and Asset Management of MRD LLC from December 2011 to June 2014. He also served as Vice President, Operations and Asset Management of MEMP GP from December 2011 to December 2012. From August 2008 to December 2011, Mr. Forney served as President of Mossback Management LLC, a private entity providing contract operating and engineering consulting services, including managing all operations and related business functions for Hungarian Horizon Energy, Ltd and Central European Drilling, Ltd in Budapest, Hungary from July 2010 to August 2011. From July 2004 to July 2008, Mr. Forney served as Vice President of Operations for Greystone Oil & Gas LLP and Managing Director of Greystone Drilling LP. Mr. Forney served as Vice President of Operations for Greystone Petroleum LLC from 2002 until 2004. Mr. Forney was Vice President and Treasurer of Goldrus Producing Company from 1997 to 2002. From 1990 to 1997, Mr. Forney held various positions for the Kelley Oil companies, which culminated in his serving concurrently as Vice President of Operations for Kelley Oil Corporation and Vice President of Concorde Gas Marketing. Prior to 1990, Mr. Forney held various drilling, production and facility construction positions with Pacific Enterprises Oil Corporation and Kerr-McGee Corporation. Mr. Forney is a registered professional engineer in Texas.

Kyle N. Roane has served as our Senior Vice President, General Counsel and Corporate Secretary since November 2014, our Vice President, General Counsel and Corporate Secretary from our formation to November 2014, and the Vice President, General Counsel and Corporate Secretary of MRD LLC from January 2014 to June 2014 and MEMP GP since January 2014. Previously, Mr. Roane served as the General Counsel and Corporate Secretary of MRD LLC and MEMP GP since February 2012. From 2005 to February 2012, Mr. Roane practiced corporate and securities law at Akin Gump Strauss Hauer & Feld L.L.P.

Gregory M. Robbins has served as our Senior Vice President, Corporate Development since November 2014, our Vice President, Corporate Development from April 2014 to November 2014 and the Vice President of Corporate Development of MRD LLC from January 2013 to June 2014 and MEMP GP since January 2013. Previously, he served as Treasurer of MRD LLC and MEMP GP from June 2011 to April 2012 and Director of Corporate Development from April 2012 to January 2013. From October 2010 to April 2011, Mr. Robbins served as Vice President and Controller of Quality Electric Steel Castings, LP. Prior to that, he was a Vice President with Guggenheim Partners, LLC from May 2006 to October 2010. Mr. Robbins worked for Wells Fargo Energy Capital, LLC from 2004 to March 2006 and Comerica Bank, Inc. from 2002 to 2004.

Dennis G. Venghaus has served as our Chief Accounting Officer since our formation, and the Controller of MRD LLC from January 2013 to June 2014 and MEMP GP since January 2012. Prior to joining MRD LLC and MEMP GP, Mr. Venghaus was with Opportune LLP from June 2010 to January 2012 as a Manager in the Complex Financial Reporting group. From September 2004 through June 2010, he held various positions in the audit practice at PricewaterhouseCoopers LLP in Houston, TX, primarily serving energy clients. Mr. Venghaus is a Certified Public Accountant.

Scott A. Gieselman has served as a member of our Board since our formation and as a member of MRD LLC s board of managers from September 2011 to June 2014 and MEMP GP s board of directors since September 2011. Mr. Gieselman has been a managing director of NGP since April 2007. Mr. Gieselman has served as a member of the board of directors of Rice Energy, Inc. since January 2014. From 1988 to April 2007, Mr. Gieselman worked in various positions in the investment banking energy group of Goldman, Sachs & Co., where he became a partner in 2002.

The Board believes that Mr. Gieselman s considerable financial and energy investment banking experience, as well as his experience on the boards of numerous private energy companies bring important and valuable skills to the Board.

Kenneth A. Hersh has served as a member of our Board since our formation and as a member of MRD LLC s board of managers from April 2011 to June 2014 and MEMP GP s board of directors since April 2011. Mr. Hersh is the Chief Executive Officer of NGP Energy Capital Management and a managing partner of NGP and has served in those or similar capacities since 1989. He currently serves as a director of NGP Capital Resources Company, a business development company that focuses on the energy industry. Mr. Hersh served as a director of Resolute Energy Corporation from September 2009 to March 2012, as a director of Eagle Rock Energy G&P, LLC, the indirect general partner of Eagle Rock Energy Partners, L.P., from March 2006 until June 2011 and Energy Transfer Partners, L.L.C., the indirect general partner of Energy Transfer Partners, L.P., a natural gas gathering and processing and transportation and storage and retail propane company, from February 2004 through December 2009, and served as a director of LE GP, LLC, the general partner of Energy Transfer Equity, L.P., from October 2002 through December 2009. Mr. Hersh currently serves on the Dean s Council of the Harvard Kennedy School and on the Advisory Councils of the Graduate School of Business at Stanford University and The Bendheim Center for Finance at Princeton University. He is also a member of the World Economic Forum where he has been a featured speaker at its annual meeting held in Davos, Switzerland.

The Board believes that Mr. Hersh brings extensive knowledge to the Board and us through his experiences in the energy industry as an investor, involvement in complex energy-related transactions and his position as Chief Executive Officer of NGP Energy Capital Management and co-manager of NGP s investment portfolio. Mr. Hersh also brings a wealth of industry-specific transactional skills, entrepreneurial ideas and a personal network of public and private capital sources that the Board believes will bring us opportunities that we may not otherwise have.

Robert A. Innamorati has served as a member of our Board since June 2014. Mr. Innamorati has served as a member of the board of directors of Memorial Production Partners GP LLC since August 2012. Mr. Innamorati has served as President of Robert A. Innamorati & Co. Inc., a private investment and advisory firm, since 1995. He previously served as President of a privately-owned diversified investment company with assets in excess of $1.5 billion from 2007 until 2012. Mr. Innamorati also held positions with Banc One Capital Corporation, Drexel Burnham Lambert & Co. Inc., PaineWebber, Inc. and Blyth Eastman Dillon & Co., Inc. He previously served for six years as a special agent with the United States Secret Service in Washington, D.C. and two years in the United States Marine Corps Reserves. Mr. Innamorati served as a board member of The Texas Rangers Baseball Club until February 2013, where he served as chairman of the compensation committee and as a member of the finance committee. Mr. Innamorati has also served as a board member for several private companies.

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The Board believes that Mr. Innamorati s extensive corporate finance, banking and private equity experience and audit committee experience will bring substantial leadership skill and experience to the Board.

Carol L. O Neill has served as a member of our Board since June 2014. Ms. O Neill has been Vice President of Strategy and Key Initiatives at Barry-Wehmiller Group, a private company engaged in the global equipment business based primarily in the US and Europe since October 2013. From April 2010 to September 2013, Ms. O Neill was Senior Vice President of Packaging at Spartech Corporation. Prior to that, Ms. O Neill served as President of Flying Food Group from August 2007 to April 2010. From 1996 to 2007, Ms. O Neill held various senior management positions at Sealed Air Corporation.

The Board believes that Ms. O Neill s considerable financial and leadership experience will bring important and valuable skills to the Board.

Pat Wood, III has served as a member of our Board since June 2014. Mr. Wood has served as a principal of Wood3 Resources, an energy infrastructure developer, since July 2005. From 2001 until July 2005, Mr. Wood served as chairman of the Federal Energy Regulatory Commission. From 1995 until 2001, he chaired the Public Utility Commission of Texas. Prior to 1995, Mr. Wood was an attorney with Baker & Botts, a global law firm, and an associate project engineer with Arco Indonesia, an oil and gas company, in Jakarta. Mr. Wood currently serves on the board of directors of Dynegy Inc., Quanta Services Inc. and SunPower Corp.

The Board believes that Mr. Wood s prior experience in corporate leadership, government and regulatory oversight, in addition to experience in public company board leadership will provide significant contributions to the Board.

Board Composition

We have seven directors. Assuming that the group consisting of MRD Holdco and certain former management members of WildHorse Resources management continue to control more than 50% of our common stock, we intend to continue to avail ourselves of the controlled company exception under NASDAQ rules, which eliminates the requirements that we (i) have a majority of independent directors, (ii) maintain a compensation committee or (iii) maintain an independent nominating function. We will be required, however, to have an audit committee comprised entirely of independent directors within the permitted phase-in period under NASDAQ rules.

As a result of the size of that group s ownership of our common stock, that group will be able to control matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions.

If at any time we cease to be a controlled company under NASDAQ rules, the Board will take all action necessary to comply with the NASDAQ rules, including appointing a majority of independent directors to the Board and ensuring we have a compensation committee and a nominating and corporate governance committee, each composed entirely of independent directors, subject to a permitted phase-in period. We will cease to qualify as a controlled company once that group ceases to control a majority of our voting stock.

Our board of directors currently consists of a single class of directors each serving one year terms. After a group including MRD Holdco and/or the Funds no longer beneficially owns or controls the vote of more than 50% of our issued and outstanding common stock, our board of directors will be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms, and such directors being removable only for cause.

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In evaluating director candidates, our Board will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the ability of the Board to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the Board to fulfill their duties. We have no minimum qualifications for director candidates. In general, however, our Board will review and evaluate both incumbent and potential new directors in an effort to achieve diversity of skills and experience among our directors and in light of the following criteria:

- experience in business, government, education, technology or public interests;
- high-level managerial experience in large organizations;
- breadth of knowledge regarding our business or industry;
- specific skills, experience or expertise related to an area of importance to us, such as energy production, consumption, distribution or transportation, government, policy, finance or law;
- moral character and integrity;
- commitment to our stockholders interests;
- ability to provide insights and practical wisdom based on experience and expertise;
- ability to read and understand financial statements; and
- ability to devote the time necessary to carry out the duties of a director, including attendance at meetings and consultation on company matters.

Although we do not have a policy in regard to the consideration of diversity in identifying director nominees, qualified candidates for nomination to the Board are considered without regard to race, color, religion, gender, ancestry or national origin.

Director Independence

Our Board has determined that, under NASDAQ listing standards and taking into account any applicable committee standards and rules under the Exchange Act, each of Robert Innamorati, Pat Wood, III and Carol O Neill is an independent director.

Audit Committee

Our Audit Committee has the composition and responsibilities described below.

Mr. Innamorati, Ms. O Neill and Mr. Wood serve as the members of our Audit Committee. Our Board has determined that Mr. Innamorati is an Audit Committee financial expert as defined by the SEC. Each member of the Audit Committee meets or will meet criteria for independence of Audit Committee members set forth in Rule 10A-3(b)(1) under the Exchange Act.

The principal duties of the Audit Committee are to assist the Board in fulfilling its responsibility to oversee management regarding:

- systems of internal control over financial reporting and disclosure controls and procedures;
- the integrity of the financial statements;
- the qualifications, engagement, compensation, independence and performance of the independent auditors and our internal audit function;
- compliance with legal and regulatory requirements;
- review of material related party transactions; and

compliance with and adequacy of the code of business and ethics, review and, if appropriate, approve any requests for written waivers sought with respect to any executive officer or director under, the code of business and ethics.

Code of Conduct

Our Board has adopted a code of business conduct and ethics (the Code of Conduct) that applies to all directors, officers and employees, including our principal executive officer, principal financial officer and principal accounting officer. The Code of Conduct is available in the Corporate Governance section of our website at www.memorialrd.com. The contents of our website are not incorporated by reference herein or otherwise a part of this prospectus. The purpose of the Code of Conduct is to promote honest and ethical conduct, including the ethical handling of actual or apparent conflicts of interest between personal and professional relationships; to promote full, fair, accurate, timely and understandable disclosure in periodic reports required to be filed by us; and to promote compliance with all applicable rules and regulations that apply to us and our officers.

Executive Compensation

Although we were formed in January 2014 and have not incurred any cost or liability with respect to compensation, management incentive or retirement benefits for our executive officers for the fiscal year ended December 31, 2013 or for any prior periods, we present historical executive compensation information for our predecessor below.

Structure

MRD LLC s named executive officers identified below also historically served as executive officers of MEMP GP. The compensation information described in this section and contained in the tables that follow reflects all compensation received by the named executive officers for the services they provided to MRD LLC as well as for the services they provided to MEMP GP and MEMP for the years covered. However, MEMP reimbursed MRD LLC for costs and expenses incurred for its or MEMP GP s benefit pursuant to the terms of the omnibus agreement. See Certain Relationships and Related Party Transactions Omnibus Agreement for more information about the omnibus agreement.

Named Executive Officers

We are currently considered an emerging growth company for purposes of the SEC s executive compensation disclosure rules. In accordance with such rules, we are required to provide a Summary Compensation Table and an Outstanding Equity Awards at Fiscal Year End Table, as well as limited narrative disclosures. Further, our reporting obligations extend only to the individuals serving as our chief executive officers, and our two other most highly compensated executive officers and only for the two most recently completed fiscal years. MRD LLC s named executive officers for 2013 were:

Name	Principal Position
John A. Weinzierl	Chief Executive Officer
Andrew J. Cozby	Vice President, Finance
Larry R. Forney	Vice President, Operations & Asset Management

Employment Agreements

Our predecessor was not party to any employment, severance or change in control agreements with any of its named executive officers. We have entered into change in control agreements with our executive officers in connection with the closing of our initial public offering. Please see Compensation Following Our Initial Public Offering Change in Control Agreements.

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Summary Compensation Table

The following table includes the compensation earned by our predecessor s named executive officers for the years ended December 31, 2013 and 2012.

Name and Position	Year	Salary	Bonus	Unit Awards(2)	Option Awards(3)	All Other Compensation(4)	Total(5)
John A. Weinzierl	2013	$ 187,500	$ 518,750	$ 2,249,996	N/A	$ 2,618,171	$ 5,574,417
(Chief Executive Officer)(1)	2012	100,000		2,500,735		202,119	2,802,854
Andrew J. Cozby	2013	$ 250,000	$ 259,375	$ 1,207,885	N/A	$ 1,293,509	$ 3,010,769
(Vice President, Finance)	2012	250,000	148,364	703,661		65,837	1,167,862
Larry R. Forney	2013	$ 250,000	$ 259,375	$ 1,231,255	N/A	$ 1,281,549	$ 3,022,179
(Vice President, Operations & Asset Management)	2012	250,000	125,000	508,088		50,522	933,610

(1) Mr. Weinzierl also served as President from April 2011 until January 2014.

(2) Reflects the aggregate grant date fair value of restricted unit awards in accordance with FASB ASC Topic 718 granted under the Memorial Production Partners GP LLC Long-Term Incentive Plan calculated by multiplying the number of restricted units granted to each executive by the closing price of MEMP common units on the date of grant. For information about assumptions made in the valuation of these awards, see Note 10 of the Notes to Consolidated and Combined Financial Statements.

(3) Each of the named executive officers received a grant of incentive units from MRD LLC in June 2012. We believe that, despite the fact that the incentive units do not require the payment of an exercise price, they are most similar economically to stock options, and as such, they are properly classified as options under the definition provided in Item 402(a)(6)(i) of Regulation S-K as an instrument with an option-like feature. Amounts reflected in this column reflect a grant date fair value of the incentive units in accordance with FASB ASC Topic 718 of $0. Because the performance conditions related to these awards were not deemed probable at the time of grant in 2012, no amounts have been reported in 2012 for purposes of this table.

(4) Amounts include (i) matching contributions under funded, qualified, defined contribution retirement plans, (ii) one-time performance bonus, (iii) the dollar value of life insurance premiums paid on behalf of such officer and (iv) the dollar value of short and long term disability insurance premiums paid on behalf of such officer.

(5) Includes, in addition to the grant date fair value of MEMP unit awards described in footnote 2, amounts reimbursed by MEMP for portions of compensation allocated to MEMP. The following supplemental table presents the amounts reimbursed by MEMP to MRD LLC for compensation allocated to MEMP for each named executive officer for the years ended December 31, 2013 and 2012:

Name	Year	MEMP Reimbursement
John A. Weinzierl	2013	$ 372,192
	2012	17,349
Andrew J. Cozby	2013	$ 261,281
	2012	66,527
Larry R. Forney	2013	$ 261,281
	2012	62,789

Narrative Disclosure to Summary Compensation Table

The following supplemental table presents the components of All Other Compensation for each of our predecessor s named executive officers for the years ended December 31, 2013 and 2012:

Name	Year	One-Time Performance	Distributions Paid On	Matching Contributions	Other	Total All Other

		Bonus	Unit Awards	401(k)		Compensation
John A. Weinzierl	2013	$ 2,293,200	$ 316,564	$ 5,917	$ 2,490	$ 2,618,171
	2012		193,690	6,000	2,429	202,119
Andrew J. Cozby	2013	$ 1,146,600	$ 129,419	$ 15,000	$ 2,490	$ 1,293,509
	2012		48,408	15,000	2,429	65,837
Larry R. Forney	2013	$ 1,146,600	$ 117,459	$ 15,000	$ 2,490	$ 1,281,549
	2012		33,093	15,000	2,429	50,522

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Outstanding Equity Awards

The awards reported here reflect the outstanding restricted MEMP common unit awards and incentive units issued to our predecessor s named executive officers as of December 31, 2013. In connection with the restructuring transactions, the MRD LLC incentive units were exchanged for substantially identical incentive units in MRD Holdco.

	Restricted MEMP Common Unit Awards			Option Awards (Incentive Unit Awards)			
	Vesting Date(1)	Number of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($)(2)	Number of Securities Underlying Unexercised Options, Unexercisable (#)(3)	Number of Securities Underlying Unexercised Options, Exercisable (#)(3)	Option Exercise Price ($)(3)	Option Expiration Date(3)
John A. Weinzierl	Various	209,647	$ 4,599,655	410	0	N/A	N/A
Andrew J. Cozby	Various	90,416	1,983,727	120	0	N/A	N/A
Larry R. Forney	Various	84,673	1,857,726	120	0	N/A	N/A

(1) One-third vests on the first, second, and third anniversaries of each date of grant. Of the 384,736 non-vested restricted MEMP common unit awards presented in the table, approximately 150,809 vest in each of 2014 and 2015 and 83,113 vest in 2016. There were 57,013 restricted MEMP common units that vested on January 9, 2014.

(2) Amounts derived by multiplying the total number of restricted MEMP common unit awards outstanding for each named executive officer by the closing price of the MEMP common units at December 31, 2013 of $21.94 per unit.

(3) Despite the fact that profits interests such as the incentive units do not require the payment of an exercise price, we believe that these awards are economically similar to stock options due to the fact that they have no value for tax purposes at grant and will obtain value only as the price of the underlying security rises, and as such, should be reported in this table as an Option award. The incentive units vest ratably over a three year period, although vesting will be fully accelerated upon the occurrence of an event which results in the Funds no longer owning a majority of the interests in, or possessing the right to appoint a majority of, the board of managers of, MRD Holdco. All of the incentive units issued to the named executive officers were issued in June 2012. All incentive units that have not vested according to their original vesting schedule at the time a named executive officer s employment with MRD Holdco is terminated for any reason or no reason, including by involuntary termination, resignation, death or disability, will be automatically forfeited without payment. In addition, all incentive units (whether vested or unvested) will be automatically forfeited without payment if the executive officer is terminated for cause (as defined in the MRD Holdco limited liability company agreement) or the executive officer resigns. The restructuring transactions described in this prospectus did not constitute a change in control resulting in the automatic vesting of the incentive units under the MRD Holdco limited liability company agreement. For a description of how and when the incentive units could obtain value and receive payment, see the discussion below.

Narrative to the Outstanding Equity Awards Table

Our predecessor granted incentive units to each of the named executive officers in order to provide them with the ability to benefit from the growth in MRD LLC s operations and business. A payout on the incentive units will occur only if, and then after, a specified level of cumulative cash distributions has been received by the Funds. Once this cumulative cash distributions threshold is achieved, all of the incentive unit holders will collectively share 10% of all further cash distributions made by MRD LLC to its members. While any such distributions made by MRD Holdco will not involve any cash payment by us, we will be required to recognize non-cash compensation expense within general and administrative expenses, which may be material, in the period in which the performance conditions are probable of being satisfied. The compensation expense recognized by us related to the incentive units will be offset by a deemed capital contribution from MRD Holdco.

Potential Payments Upon Termination or Change in Control

Awards under the Memorial Production Partners GP Long-Term Incentive Plan may vest and/or become exercisable, as applicable, upon a "change of control" of MRD Holdco or MEMP GP, as determined by the plan administrator. Under the Memorial Production Partners GP Long-Term Incentive Plan, a "change of control" will be deemed to have occurred upon one or more of the following events (i) the managers of MRD Holdco appointed by the Funds or their affiliates do not constitute a majority of the board of managers of MRD Holdco;

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(ii) MRD Holdco, the Funds or any of their affiliates do not have the right to appoint or nominate a majority of the board of directors of MEMP GP; (iii) the members of MEMP GP approve and implement, in one or a series of transactions, a plan of complete liquidation of MEMP GP; (iv) the sale or other disposition by MEMP GP of all or substantially all of its assets in one or more transactions to any person or entity other than MEMP GP or an affiliate of MEMP GP or the Funds; or (v) a person or entity other than MEMP GP or an affiliate of MEMP GP or the Funds becomes the general partner of MEMP. The consequences of the termination of a grantee s employment, consulting arrangement or membership on the board of managers or directors will be determined by the plan administrator in the terms of the relevant award agreement.

As described above, the vesting of the incentive units will be fully accelerated upon the occurrence of an event which results in the Funds no longer owning a majority of the interests in, or possessing the right to appoint a majority of the board of managers of, MRD Holdco.

We adopted the Memorial Resource Development Corp. 2014 Long Term Incentive Plan, as further described in Compensation Following Our Initial Public Offering 2014 Long Term Incentive Plan, and entered into change in control agreements with our executive officers, as further described in Compensation Following Our Initial Public Offering Change in Control Agreements in connection with the closing of our initial public offering.

Manager Compensation

None of MRD LLC s managers, whether or not employed by MRD LLC, received compensation for services to MRD LLC as a manager for the year ended December 31, 2013.

Compensation Following Our Initial Public Offering

Our named executive officers also serve as executive officers of MEMP GP. MEMP reimburses us for costs and expenses incurred for its or MEMP GP s benefit pursuant to the terms of the omnibus agreement, including an allocated portion of each such executive s compensation. See Certain Relationships and Related Party Transactions Omnibus Agreement for more information about the omnibus agreement. We have sole responsibility and authority for compensation-related decisions for our executive officers and other personnel.

We employ a compensation philosophy that emphasizes pay-for-performance, based on a combination of our performance and the individual s impact on our performance and places the majority of each officer s compensation at risk. The compensation of our executive and non-executive officers includes a significant component of incentive compensation based on our performance. The performance metrics governing incentive compensation are not tied in any way to the performance of entities other than us. We believe this pay-for-performance approach generally aligns the interests of our executive officers with that of our stockholders, and at the same time enables us to maintain a lower level of base overhead in the event our operating and financial performance fails to meet expectations.

Our executive compensation is designed to attract and retain individuals with the background and skills necessary to successfully execute our business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of our stockholders, and to reward success in reaching such goals. We use three primary elements of compensation to fulfill that design salary, cash bonus and long-term equity incentive awards. Cash bonuses and equity incentives (as opposed to salary) represent the performance driven elements. They are also flexible in application and can be tailored to meet our objectives. The determination of specific individuals cash bonuses reflects their relative contribution to achieving or exceeding annual goals, and the determination of specific individuals long-term incentive awards is based on their expected contribution in respect of longer term performance objectives.

We do not have a defined benefit or pension plan for our executive officers because we believe such plans primarily reward longevity rather than performance. We provide a basic benefits package generally to all employees, which includes a 401(k) plan and health, disability and life insurance.

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We expect that our named executive officers for the year ended December 31, 2014 will be the following:

Name	Principal Position
John A. Weinzierl	Chief Executive Officer
William J. Scarff	President
Andrew J. Cozby	Senior Vice President and Chief Financial Officer

The following table sets forth the expected base salaries and expected annual target bonus opportunities for our named executive officers for 2014:

Name	2014 Base Salary	2014 Target Bonus Opportunity (% of Base Salary)
John A. Weinzierl	$ 350,000	100%
William J. Scarff	$ 350,000	100%
Andrew J. Cozby	$ 350,000	80%

Initial Public Offering Bonuses

We granted certain employees, including our named executive officers, bonuses in connection with the completion of our initial public offering. The bonuses were granted to the employees in the form of restricted stock awards that are governed by the Plan described below. The restricted stock awards were granted following the closing of our initial public offering and vest ratably on a four-year annual vesting schedule. These bonuses totaled 1,052,632 shares for all employees, including our named executive officers. Of our 2014 named executive officers, Mr. Weinzierl received an award of 184,211 shares, Mr. Scarff 131,579 shares and Mr. Cozby 97,368 shares.

Director Compensation

Our officers or employees who also serve as our directors do not receive additional compensation for their service as a director. Our directors who are not our officers or employees do receive compensation as nonemployee directors. Each non-employee director receives an annual retainer of $100,000 and an additional retainer of $7,500 for service as the chair of the audit committee. We also grant equity-based awards equal to $100,000 to non-employee directors upon appointment to the Board and on an annual basis. Non-employee directors are reimbursed for all out-of-pocket expenses incurred in connection with attending Board or committee meetings. Each director is indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

Change in Control Agreements

We have entered into change in control agreements with our executive officers. The change in control agreements continue in effect until the earlier of (i) a separation from service other than on account of a qualifying termination (as defined below), (ii) the Company s satisfaction of all of our obligations under the change in control agreement, or (iii) the execution of a written agreement between the Company and the executive officer terminating the change in control agreement.

Under the terms of each change in control agreement, if an executive s employment is terminated on account of a qualifying termination, then subject to such executive s signing and not revoking a separation agreement and release of claims, then such executive will be entitled to:

- receive a lump sum payment of equal to a specified percentage of such executive s (a) annual base salary and (b) target bonus, in each case, at the highest rate in effect during the twelve month period prior to the date in which the qualifying termination occurs, which percentage is 250/200/150%;

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the vesting of all outstanding unvested awards previously granted to such executive under the Memorial Resource Development Corp. 2014 Long Term Incentive Plan;

reimbursement for the amount of COBRA continuation premiums (less required co-pay) until the earlier of (a) twelve months following the qualifying termination and (b) such time as such executive is no longer eligible for COBRA continuation coverage;

financial counseling services for twelve months following the qualifying termination, subject to a maximum benefit of $30,000; and

outplacement counseling services for twelve months following the qualifying termination, subject to a maximum value of $30,000.

For purposes of the above, qualifying termination means, as to any executive, the separation of service on account of (i) an involuntary termination by the Company without cause or (ii) such executive s voluntary resignation for good reason, in each case, within six months prior to, or twenty-four months following, a change in control. The term cause means (a) such executive s commission of, conviction for, plea of guilty or nolo contendere to a felony or a crime involving moral turpitude; (b) engaging in conduct that constitutes fraud, gross negligence or willful misconduct that results or would reasonably be expected to result in material harm to the Company or our business or reputation; (c) breach of any material terms of such executive s employment, including any of our policies or code of conduct; or (d) failure to perform such executive s duties for the Company. The term good reason means the occurrence of one of the following without an executive s express written consent (i) a material reduction of such executive s duties, position or responsibilities, or such executive s removal from such position and responsibilities, unless such executive is offered a comparable position (i.e., a position of equal or greater organizational level, duties, authority, compensation, title and status); (ii) a material reduction by the Company of such executive s base compensation (base salary and target bonus) as in effect immediately prior to such reduction; or (iii) such executive is requested to relocate (except for office relocations that would not increase such executive s one way commute by more than 50 miles). The term change in control has the meaning ascribed to such term in the Memorial Resource Development Corp. 2014 Incentive Award Plan and is described in the discussion below under 2014 Long Term Incentive Plan Merger, recapitalization or change in control.

In the event that the Board determines that payments to be made to an executive under the change in control agreement would constitute excess parachute payments subject to excise tax under Section 4999 of the Internal Revenue Code, then the amount of such payments shall either (i) be reduced so that such payments will not be subject to such excise tax or (ii) paid in full, whichever results in the better net after tax position for the executive.

2014 Long Term Incentive Plan

We adopted the Memorial Resource Development Corp. 2014 Long Term Incentive Plan (the Plan) for the employees of the Company and our directors. The description of the Plan set forth below is a summary of the material features of the Plan. This summary is qualified in its entirety by reference to the Plan, a copy of which has been filed as an exhibit to this registration statement. The purpose of the Plan is to provide a means to attract and retain individuals to serve as our directors and employees by affording such individuals a means to acquire and maintain ownership of awards, the value of which is tied to the performance of our common stock. The restricted stock units granted in connection with the closing of our initial public offering described below should be not be interpreted as representative of the Plan awards that may be granted in the future.

The Plan provides for potential grants of: (i) incentive stock options qualified as such under U.S. federal income tax laws (incentive options); (ii) stock options that do not qualify as incentive stock options (nonstatutory options, and together with incentive options, options); (iii) stock appreciation rights; (iv) restricted stock awards; (v) restricted stock units (RSUs); (vi) bonus stock; (vii) dividend equivalents,

(viii) performance awards; (ix) annual incentive awards; and (x) other stock-based awards (collectively referred to as awards).

Administration

Our Board administers the Plan pursuant to its terms and all applicable state, federal or other rules or laws, and may delegate its duties and responsibilities as Plan administrator to a committee composed of two or more directors, subject to certain limitations. The Plan administrator has the power to determine to whom and when awards will be granted, determine the amount of awards (measured in cash or in shares of our common stock), proscribe and interpret the terms and provisions of each award agreement (the terms of which may vary), make determinations of fair market value, accelerate the exercise terms of an option, delegate duties under the Plan, terminate, modify or amend the Plan in certain cases and execute all other responsibilities permitted or required under the Plan. The Plan administrator is limited in its administration of the Plan only in the event that a performance award or annual incentive award intended to comply with section 162(m) of the Code requires the Board to be composed solely of outside directors at a time when not all directors are considered outside directors for purposes of section 162(m) of the Code; at such time any director that is not qualified to grant or administer such an award will recuse himself from the Board s actions with regard to that award.

Securities Offered

The maximum aggregate number of shares of common stock that may be issued pursuant to any and all awards under the Plan shall not exceed 19,250,000 shares, subject to adjustment due to recapitalization or reorganization, or related to forfeitures or the expiration of awards, as provided under the Plan.

If common stock subject to any award is not issued or transferred, or ceases to be issuable or transferable for any reason, including (but not exclusively) because shares are withheld or surrendered in payment of taxes or any exercise or purchase price relating to an award or because an award is forfeited, terminated, expires unexercised, is settled in cash in lieu of common stock or is otherwise terminated without a delivery of shares, those shares of common stock will again be available for issue, transfer or exercise pursuant to awards under the Plan to the extent allowable by law.

> *Options*. We may grant options to eligible persons including: (i) incentive options (only to our employees or those of our subsidiaries) which comply with section 422 of the Code; and (ii) nonstatutory options. The exercise price of each option granted under the Plan will be stated in the option agreement and may vary; however, the exercise price for an option must not be less than the fair market value per share of common stock as of the date of grant (or 110% of the fair market value for certain incentive options), nor may the option be re-priced without the prior approval of our stockholders. Options may be exercised as the Board determines, but not later than ten years from the date of grant. The Board will determine the methods and form of payment for the exercise price of an option (including, in the discretion of the Board, payment in common stock, other awards or other property) and the methods and forms in which common stock will be delivered to a participant.

Stock appreciation rights (SARs) may be awarded in connection with an option (or as SARs that stand alone, as discussed below). SARs awarded in connection with an option will entitle the holder, upon exercise, to surrender the related option or portion thereof relating to the number of shares for which the SAR is exercised. The surrendered option or portion thereof will then cease to be exercisable. Such SAR is exercisable or transferable only to the extent that the related option is exercisable or transferable.

SARs. A SAR is the right to receive a share of common stock, or an amount equal to the excess of the fair market value of one share of the common stock on the date of exercise over the grant price of the SAR, as determined by the Board. The exercise price of a share of common stock subject to the SAR shall be determined by the Board, but in no event shall that exercise price be less than the fair market value of the common stock on the date of grant. The Board will have the discretion to determine other terms and conditions of a SAR award.

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Restricted stock awards. A restricted stock award is a grant of shares of common stock subject to a risk of forfeiture, performance conditions, restrictions on transferability and any other restrictions imposed by the Board in its discretion. Restrictions may lapse at such times and under such circumstances as determined by the Board. Except as otherwise provided under the terms of the Plan or an award agreement, the holder of a restricted stock award will have rights as a stockholder, including the right to vote the common stock subject to the restricted stock award or to receive dividends on the common stock subject to the restricted stock award during the restriction period. The Board shall provide, in the restricted stock award agreement, whether the restricted stock will be forfeited and reacquired by us upon certain terminations of employment. Unless otherwise determined by the Board, common stock distributed in connection with a stock split or stock dividend, and other property distributed as a dividend, will be subject to restrictions and a risk of forfeiture to the same extent as the restricted stock award with respect to which such common stock or other property has been distributed.

Restricted stock units. RSUs are rights to receive common stock, cash, or a combination of both at the end of a specified period. The Board may subject RSUs to restrictions (which may include a risk of forfeiture) to be specified in the RSU award agreement, and those restrictions may lapse at such times determined by the Board. Restricted stock units may be settled by delivery of common stock, cash equal to the fair market value of the specified number of shares of common stock covered by the RSUs, or any combination thereof determined by the Board at the date of grant or thereafter. Dividend equivalents on the specified number of shares of common stock covered by RSUs may be paid on a current or deferred basis, as determined by the Board on or following the date of grant.

Bonus stock awards. The Board will be authorized to grant common stock as a bonus stock award. The Board will determine any terms and conditions applicable to grants of common stock, including performance criteria, if any, associated with a bonus stock award.

Dividend equivalents. Dividend equivalents are rights to receive cash, stock, other awards, or other property equal in value to dividends paid with respect to a specified number of shares of common stock. Dividend equivalents may be awarded on a free-standing basis or in connection with another award. The Board may provide that dividend equivalents shall be paid or distributed when accrued or shall be deemed to have been reinvested in additional common stock, awards, or other investment vehicles, and be subject to such restrictions on transferability and risks of forfeiture, as determined by the Board.

Performance awards and annual incentive awards. The Board may designate that certain awards granted under the Plan constitute performance awards. A performance award is any award the grant, exercise or settlement of which is subject to one or more performance standards. An annual incentive award is an award based on a performance period of the fiscal year, and is also conditioned on one or more performance standards. One or more of the following business criteria for the company, on a consolidated basis, and/or for specified subsidiaries, may be used by the Board in establishing performance goals for such performance awards or annual incentive awards that are intended to meet the performance-based compensation criteria of section 162(m) of the Code: (i) earnings per share; (ii) increase in revenues; (iii) increase in cash flow; (iv) increase in cash flow from operations; (v) increase in cash flow return; (vi) return on net assets; (vii) return on assets; (viii) return on investment; (ix) return on capital; (x) return on equity; (xi) economic value added; (xii) operating margin; (xiii) contribution margin; (xiv) net income; (xv) net income per share; (xvi) pretax earnings; (xvii) pretax operating earnings after interest expense and before incentives, service fees and extraordinary or special items; (xviii) pretax earnings before interest, depreciation and amortization; (xix) total stockholder return; (xx) debt reduction; (xxi) market share; (xxii) change in the fair market value of the common stock; (xxiii) operating income; or (xxiv) lease operating expenses. The Board may exclude the impact of any of the following events or occurrences which the Board determines should appropriately be excluded: (i) asset write-downs; (ii) litigation, claims, judgments or settlements; (iii) the effect of changes in tax law or other such laws or regulations affecting reported results; (iv) accruals for reorganization and restructuring programs; (v) any extraordinary, unusual or nonrecurring items as described in the Accounting Standards Codification Topic 225, as the same may be amended or superseded from time to time; (vi) any change in accounting principles as defined in the Accounting Standards Codification Topic 250, as the same may be amended or superseded from time to time; (vii) any loss from a discontinued operation as described in the Accounting Standards Codification Topic 360, as the same may be amended or superseded from time to time; (viii) goodwill impairment charges; (ix) operating results for any business acquired during the calendar year; (x) third party expenses associated with any acquisition by us or any subsidiary; and (xi) to the extent set forth with reasonable particularity in connection with the establishment of performance goals, any other extraordinary events or occurrences identified by the Board. The Board may also use any of the above goals determined on an absolute or relative basis or as compared to the performance of a published or special index deemed applicable by the Board including, but not limited to, the Standard & Poor s 500 stock index or a group of comparable companies.

Other stock-based awards. The Board is authorized, subject to limitations under applicable law, to grant such other awards that may be denominated or payable in, valued in whole or in part by reference to, or otherwise based on, or related to, our common stock, as deemed by the Board to be consistent with the purposes of the Plan. These other awards could include convertible or exchangeable debt securities, other rights convertible or exchangeable into common stock, purchase rights for common stock, awards with value and payment contingent upon performance of the Company or any other factors designated by the Board, and awards valued by reference to the book value of our common stock or the value of securities of or the performance of specified subsidiaries of the Company. The Board shall determine the terms and conditions of these awards.

Performance awards or annual incentive awards granted to eligible persons who are deemed by the Board to be covered employees pursuant to section 162(m) of the Code shall be administered in accordance with the rules and regulations issued under section 162(m) of the Code. The Board may also impose individual performance criteria on the awards, which, if required for compliance with section 162(m) of the Code, will be approved by our stockholders. In any calendar year, a covered employee may not be granted an award of more than 2.5 million of our shares of stock, or cash-based award having a value of more than $50 million.

Tax withholding. At our discretion, subject to conditions that the Board may impose, a participant s minimum statutory tax withholding with respect to an award may be satisfied by withholding from any payment related to an award or by the withholding of shares of common stock issuable pursuant to the award based on the fair market value of the shares.

Merger, recapitalization or change in control. If any change is made to our capitalization, such as a stock split, stock combination, stock dividend, exchange of shares or other recapitalization, merger or otherwise, which results in an increase or decrease in the number of outstanding shares of common stock, appropriate adjustments will be made by the Board in the shares subject to an award under the Plan. We will also have the discretion to make certain adjustments to awards in the event of a change in control, such as accelerating the exercisability of options or SARs, requiring the surrender of an award, with or without consideration, or making any other adjustment or modification to the award we feel is appropriate in light of the specific transaction.

A change in control is defined in the Plan to mean (i) subject to certain exceptions, the acquisition by a person or group of more than 50% of shares of our outstanding common stock or the total combined voting power of our outstanding securities, (ii) individuals who constitute our incumbent board cease for any reason to constitute at least a majority of the Board, (iii) a merger, consolidation, reorganization or business combination or the sale or other disposition of all or substantially all of our assets or an acquisition of assets of another entity unless following such transaction, (a) our stockholders continue to own more than 50% of the voting power of the resulting entity, (b) no person (excluding any entity controlled by or under common control with NGP Energy Capital Management, L.L.C.) beneficially owns, directly or indirectly, 20% or more of the then outstanding shares of common stock or common equity interests of the resulting entity or the combined voting power of the then outstanding voting securities to the extent that such ownership results solely from ownership of the Company prior to the transaction or event and (c) a majority of the members of the board of directors of the

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resulting entity were members of our incumbent board at the time of the action of our Board providing for such transaction or event or (iv) approval by our stockholders of the Company s complete liquidation or dissolution.

Awards Granted Following Our Initial Public Offering

Following the closing of our initial public offering, our Board approved an award of 1,052,632 shares of restricted stock under the Plan to certain of our key employees, including each of our executive officers, as further described in Compensation Following Our initial public offering Initial Public Offering Bonuses. We do not currently expect that our Board will approve any additional awards under the Plan for the remainder of 2014.

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PRINCIPAL AND SELLING STOCKHOLDERS

The following table provides certain information regarding the beneficial ownership of our outstanding capital stock as of November 1, 2014, and after giving effect to the offering, for:

- each person who then will beneficially own more than 5% of the then outstanding capital stock on a fully diluted basis;
- each of our directors;
- each of our named executive officers;
- each selling stockholder; and
- all of our directors and executive officers as a group.

The amounts and percentages of common stock beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities and a person may be deemed a beneficial owner of securities as to which he has no economic interest. Except as indicated by footnote and in the next paragraph, the persons named in the table below have sole voting and investment power with respect to all shares of common stock shown as beneficially owned by them. Unless otherwise noted, the mailing address of each person or entity named in the table is 500 Dallas Street, Suite 1800, Houston, Texas 77002.

Upon the closing of this offering, the group consisting of MRD Holdco, Messrs. Bahr and Graham, and certain other former management members of WildHorse Resources will continue to control a majority of our voting common stock. As a result, we will continue to be a controlled company within the meaning of the NASDAQ listing rules. However, the number of shares reflected in the table below as beneficially owned by each of the members of that group does not include shares held by the other members of that group that are subject to the terms of the voting agreement pursuant to which, among other things, such group members have agreed to vote as directed by MRD Holdco.

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The selling stockholders have granted the underwriters the option to purchase up to an additional 4,500,000 shares of common stock and will sell such shares only to the extent such option is exercised. The selling stockholders may be deemed under federal securities laws to be underwriters with respect to the common stock they may sell in connection with this offering. The number of shares being offered by the selling stockholders in the table below assumes no exercise of the underwriters option to purchase additional shares of common stock from the selling stockholders.

Name of beneficial owner	Shares beneficially owned prior to offering Number	Percentage	Shares being offered	Shares beneficially owned after offering Number	Percentage
5% Stockholders and/or Selling Stockholders:					
MRD Holdco LLC (MRD Holdco)(1)	100,945,677	52.2%	23,196,734	77,748,943	40.2%
Anthony Bahr(3)(4)(5)	15,092,953	7.8%	2,513,365	12,579,588	6.5%
Jay Graham(3)(4)(5)	15,092,953	7.8%	2,513,365	12,579,588	6.5%
Paul Eschete(3)(4)	2,752,635	1.4%	471,562	2,281,073	1.2%
Joseph Wyszynski (3)(4)	1,772,136	*	303,590	1,468,546	*
Steve Habachy(3)(4)	1,770,620	*	303,330	1,467,290	*
Steve Eckerman(3)(4)	1,740,491	*	298,169	1,442,322	*
Terence Lynch(3)(4)	1,054,843	*	180,708	874,135	*
William Hebert(3)(4)	506,325	*	86,740	419,585	*
Marcus Spillson(3)(4)	126,581	*	18,431	108,150	*
John Nabors(3)(4)	316,453	*	54,213	262,240	*
Tyler Fenley(3)(4)	274,259	*	38,108	236,151	*
Herbert Cole(3)(4)	126,581	*	21,685	104,896	*
Directors and Named Executive Officers:					
Kenneth A. Hersh(2)	100,945,677	52.2%		77,748,943	40.2%
Tony R. Weber					
John A. Weinzierl	294,211	*		294,211	*
Scott A. Gieselman					
William J. Scarff	136,579	*		136,579	*
Andrew J. Cozby	103,368	*		103,368	*
Larry R. Forney	97,368	*		97,368	*
Robert A. Innamorati	43,390	*		43,390	*
Carol L. O Neill	7,763	*		7,763	*
Pat Wood, III	20,263	*		20,263	*
All executive officers and directors as a group (13 persons)	101,882,041	52.6%		78,685,307	40.7%

* Less than 1%.

(1) The board of managers of MRD Holdco has voting and dispositive power over these shares. The board of managers of MRD Holdco consists of John A. Weinzierl, Kenneth A. Hersh, Scott A. Gieselman and Tony R. Weber, none of whom individually have voting and dispositive power over these shares. Each such person expressly disclaims beneficial ownership over these shares, except to the extent of any pecuniary interest therein. MRD Holdco is owned by Natural Gas Partners VIII, L.P. (NGP VIII), Natural Gas Partners IX, L.P. (NGP IX) and NGP IX Offshore Holdings, L.P. (NGP IX Offshore). NGP VIII, NGP IX and NGP IX Offshore may be deemed to share voting and dispositive power over the reported securities; thus, each may also be deemed to be the beneficial owner of these securities. Each of NGP VIII, NGP IX and NGP IX Offshore disclaims beneficial ownership of the reported securities in excess of such entity s respective pecuniary interest in the securities. G.F.W. Energy VIII, L.P., GFW VIII, L.L.C., G.F.W. Energy IX, L.P. and GFW IX, L.L.C. may be deemed to beneficially own the shares held by MRD Holdco that are attributable to NGP VIII, NGP IX and NGP IX Offshore by virtue of GFW VIII, L.L.C. being the sole general partner of G.F.W. Energy VIII, L.P. (which is the general partner of NGP VIII) and GFW IX, L.L.C. being the sole general partner of G.F.W. Energy IX, L.P. (which is the general partner of NGP IX and NGP IX Offshore). Kenneth A. Hersh, one of our directors and who is an Authorized Member of each of GFW VIII, L.L.C. and GFW IX, L.L.C., may also be deemed to share the power to vote, or to direct the vote, and to dispose, or to direct the disposition, of those shares. Mr. Hersh does not own directly any shares.

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(2) G.F.W. Energy VIII, L.P., GFW VIII, L.L.C., G.F.W. Energy IX, L.P. and GFW IX, L.L.C. may be deemed to beneficially own the shares held by MRD Holdco that are attributable to NGP VIII, NGP IX and NGP IX Offshore by virtue of GFW VIII, L.L.C. being the sole general partner of G.F.W. Energy VIII, L.P. (which is the general partner of NGP VIII) and GFW IX, L.L.C. being the sole general partner of G.F.W. Energy IX, L.P. (which is the general partner of NGP IX and NGP IX Offshore). Kenneth A. Hersh, one of our directors and who is an Authorized Member of each of GFW VIII, L.L.C. and GFW IX, L.L.C., may also be deemed to share the power to vote, or to direct the vote, and to dispose, or to direct the disposition, of those shares. Mr. Hersh does not own directly any shares.

(3) The address for these beneficial owners is 9805 Katy Freeway, Suite 400, Houston, TX 77024.

(4) Each of these selling stockholders is a former officer or employee of our wholly-owned subsidiary, WildHorse Resources, LLC.

(5) Includes 580,000 shares owned by WHR Incentive LLC, a limited liability company beneficially owned by Messrs. Anthony Bahr and Jay Graham. Each of Messrs. Bahr and Graham may be deemed to share voting and dispositive power over the shares held by WHR Incentive LLC; thus, each may also be deemed to be the beneficial owner of these securities. Each of Messrs. Bahr and Graham disclaims beneficial ownership of the reported securities in excess of such individual s pecuniary interest in the securities.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Corporate Restructuring

In connection with our corporate restructuring, we engaged in transactions with certain affiliates and our existing equity holders. Pursuant to a contribution agreement, MRD LLC contributed to us substantially all of its assets, comprised of: (i) 100% of the ownership interests in Classic Hydrocarbons Holdings, L.P., Classic Hydrocarbons GP Co., L.L.C., Black Diamond Minerals, LLC, Beta Operating Company, LLC, Memorial Resource Finance Corp. and MRD Operating LLC; (ii) 99.9% of the membership interests in WildHorse Resources, the owner of our properties in the Terryville Complex; and (iii) MEMP GP (including MEMP GP s ownership of 50% of MEMP s incentive distribution rights). In exchange, we issued 128,665,677 shares of our common stock to MRD LLC, which MRD LLC then immediately distributed to MRD Holdco. We assumed the obligations of MRD LLC under the PIK notes, including the obligation to reimburse MRD LLC for the June 15, 2014 interest payment made on the PIK notes.

Pursuant to another contribution agreement, certain former management members of WildHorse Resources contributed to us their outstanding incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources, and we issued 42,334,323 shares of our common stock and paid cash consideration of approximately $30.0 million to such former management members of WildHorse Resources.

Historical Transactions with Affiliates

MRD LLC was formed in April 2011 and capitalized in connection with the December 2011 initial public offering of MEMP. The limited liability company agreement of MRD LLC provided for a number of different classes of units, all of which were owned by the Funds. In June 2012, MRD LLC issued incentive units to certain of its officers and employees. These incentive units only participated in distributions upon liquidation events meeting certain requisite financial return thresholds. Before the closing of our initial public offering, the Funds contributed all of their ownership of MRD LLC to MRD Holdco and the owners of incentive units in MRD LLC exchanged those interests for substantially identical incentive units in MRD Holdco.

Voting Agreement

In connection with the closing of our initial public offering, we entered into a voting agreement with MRD Holdco, WHR Incentive LLC, a limited liability company beneficially owned by Anthony Bahr and Jay Graham and certain former management members of WildHorse Resources that contributed their ownership of WildHorse Resources to us in the restructuring transactions. Among other things, the voting agreement provides that those former management members of WildHorse Resources will vote all of their shares of our common stock as directed by MRD Holdco. The voting agreement also prohibits the transfer of any shares of our common stock by the former management members of WildHorse Resources until after the termination of the services agreement described below; provided, however, that the former management members of WildHorse Resources (other than Anthony Bahr or Jay Graham) may transfer their shares of our common stock after the 180 day lock-up period following our initial public offering has expired; provided, however, that Jay Graham or Anthony Bahr are not prohibited from exercising their piggyback registration rights pursuant to the registration rights agreement described below during such 180 day lock-up period.

Further, so long as the services agreement is in effect, the former management members of WildHorse Resources will have the right to appoint two board observers, Anthony Bahr and Jay Graham, to attend all meetings of our Board in a non-voting, observer capacity. No board observer will have a vote on our Board. The members of the Board can exclude any board observer from any board meeting so that the members of the Board may meet in executive session, to protect attorney-client privilege, or in connection with a conflict of interest.

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The voting agreement also provides MRD Holdco with the right to designate up to three nominees to our Board, provided that such number of nominees shall be reduced to two, one and zero if the Funds and their affiliates collectively own less than 35%, 15% and 5%, respectively, of the outstanding shares of our common stock. The voting agreement also requires us and the stockholders party thereto to take all necessary actions, to the fullest extent permitted by applicable law (including with respect to any fiduciary duties under Delaware law), including voting their shares of our common stock, to cause the election of the nominees designated by MRD Holdco. In addition, the voting agreement provides that for so long as MRD Holdco has the right to designate two directors to the Board, we will cause any committee of our Board to include in its membership at least one director designated by MRD Holdco, except to the extent that such membership would violate applicable securities laws or stock exchange rules.

Registration Rights Agreement

In connection with the closing of our initial public offering, we entered into a registration rights agreement with MRD Holdco and former management members of WildHorse Resources, Jay Graham (Graham) and Anthony Bahr (Bahr). Pursuant to the registration rights agreement, we have agreed to register the sale of shares of our common stock under certain circumstances.

Demand Rights

Subject to the limitations set forth below, each of MRD Holdco, Graham and Bahr (or their permitted transferees) has the right to require us, by written notice, to prepare and file a registration statement registering the offer and sale of a certain number of their shares of common stock. Generally, we are required to provide notice of the request within five business days following the receipt of such demand request to all other holders of registrable securities, who may, in certain circumstances, participate in the registration. Subject to certain exceptions, we will not be obligated to effect a demand registration within 90 days after the closing of any underwritten offering of shares of our common stock. Further, we are not obligated to effect, (i) at the request of MRD Holdco, more than a total of three demand registrations through December 31, 2016 or, after January 1, 2017, more than one demand registration per calendar year; and (ii) any demand registrations at the request of either Graham or Bahr before the termination of the services agreement described below or, after the termination of the services agreement, more than two demand registrations at the request of each of Graham or Bahr.

We are also not obligated to effect any demand registration in which the anticipated aggregate offering price included in such offering is less than $50 million. Once we are eligible to effect a registration on Form S-3, any such demand registration may be for a shelf registration statement. We will be required to use all commercially reasonable efforts to maintain the effectiveness of any registration statement until all shares covered by such registration statement have been sold.

In addition, each of MRD Holdco, Graham and Bahr (or their permitted transferees) has the right to require us, subject to certain limitations, to effect a distribution of any or all of their shares of common stock by means of an underwritten offering. In general, any demand for an underwritten offering (other than the first requested underwritten offering made in respect of a prior demand registration and other than a requested underwritten offering made concurrently with a demand registration) shall constitute a demand request subject to the limitations set forth above.

Piggyback Rights

Subject to certain exceptions, if at any time we propose to register an offering of common stock or conduct an underwritten offering, whether or not for our own account, then we must notify MRD Holdco, Graham and Bahr (or their permitted transferees) of such proposal at least five business days before the anticipated filing date or commencement of the underwritten offering, as applicable, to allow them to include a specified number of their shares in that registration statement or underwritten offering, as applicable.

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Conditions and Limitations; Expenses

These registration rights are subject to certain conditions and limitations, including the right of the underwriters to limit the number of shares to be included in a registration and our right to delay or withdraw a registration statement under certain circumstances. We will generally pay all registration expenses in connection with our obligations under the registration rights agreement, regardless of whether a registration statement is filed or becomes effective.

Omnibus Agreement

On December 14, 2011, in connection with the closing of MEMP s initial public offering, MRD LLC entered into an omnibus agreement with MEMP and its general partner. In connection with the restructuring transactions, we succeeded to all of MRD LLC s duties and obligations under the omnibus agreement.

Pursuant to the omnibus agreement, MEMP is required to reimburse us for all expenses incurred by us (or payments made on MEMP s behalf) in conjunction with our provision of general and administrative services to MEMP, including, but not limited to, public company expenses and an allocated portion of the salary and benefits of the executive officers of MEMP s general partner and our other employees who perform services for MEMP or on MEMP s behalf. MEMP is also obligated to reimburse us for insurance coverage expenses we incur with respect to MEMP s business and operations and with respect to director and officer liability coverage for the officers and directors of MEMP s general partner.

Pursuant to the omnibus agreement, we will indemnify MEMP s general partner and MEMP against (i) title defects and (ii) income taxes attributable to pre-closing ownership or operation of the assets we contributed to MEMP in connection with MEMP s initial public offering, including any income tax liabilities related to such contribution occurring on or prior to the closing of MEMP s initial public offering.

Our indemnification obligation will survive until December 2014 with respect to title defects and for sixty days after the expiration of the applicable statute of limitations with respect to income taxes. All title claims are subject to a $25,000 per claim de minimus exception and an aggregate $2,000,000 deductible.

Pursuant to the omnibus agreement, MEMP must indemnify us for any liabilities incurred by us attributable to the operating and administrative services provided to MEMP under the omnibus agreement, other than liabilities resulting from our bad faith, fraud, gross negligence or willful misconduct. In addition, we must indemnify MEMP for any liability MEMP incurs as a result of our bad faith or willful misconduct in providing operating and administrative services under the omnibus agreement. We may terminate the omnibus agreement in the event that we cease to be an affiliate of MEMP and may also terminate the omnibus agreement in the event of MEMP s material breach of the agreement, including failure to pay amounts due thereunder in accordance with its terms.

Under the omnibus agreement, none of the parties thereto nor any of their respective affiliates have any obligation to offer, or provide any opportunity to pursue, purchase or invest in, any business opportunity to any other party or their affiliates. Furthermore, the omnibus agreement does not restrict any of the parties thereto and their respective affiliates from competing with either us, MEMP or MEMP s general partner.

Beta Management Agreement

On December 12, 2012, MRD LLC entered into a management agreement with its wholly-owned subsidiary, Beta Operating Company, LLC pursuant to which MRD LLC agreed to provide management and administrative oversight with respect to the services provided by such subsidiary under certain operating agreements with a subsidiary of MEMP, in exchange for an annual management fee. In connection with the restructuring transactions, we succeeded to this management agreement and we receive approximately $0.4 million from MEMP annually under that agreement.

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Services Agreement

Upon the closing of our initial public offering, we entered into a services agreement with WildHorse Resources and WildHorse Resources Management Company, LLC (WHR Management Company), pursuant to which WHR Management Company provides operating and administrative services to us for twelve months relating to the Terryville Complex. In exchange for such services, we pay a monthly management fee to WHR Management Company of approximately $1.0 million excluding third party COPAS income credits.

WHR Management Company may only terminate the services agreement by providing 90-days prior written notice to the Company after the six-month anniversary of the date of the agreement. We may terminate the services agreement at any time by providing written notice to WHR Management Company. The services agreement may only be assigned by either party with the other party s consent. WHR Management Company is a subsidiary of WildHorse Resources II, LLC, an affiliate of the Company. NGP and certain former management members of WildHorse Resources own WildHorse Resources II, LLC.

Gas Processing Agreement

On March 17, 2014, WildHorse Resources entered into a gas processing agreement with PennTex North Louisiana, LLC (PennTex). PennTex is a joint venture among certain affiliates of NGP in which MRD Midstream LLC owns a minority interest. Once PennTex s processing plant becomes operational, it will process natural gas produced from wells located on certain leases owned by WildHorse Resources in the state of Louisiana. The agreement has a 15-year primary term, subject to one-year extensions at either party s election. WildHorse Resources will pay PennTex a monthly fee, subject to an annual inflationary escalation, based on volumes of natural gas delivered and processed. Once the plant is declared operational, WildHorse Resources will be obligated to pay a minimum processing fee equal to approximately $18.3 million on an annual basis, subject to certain adjustments and conditions. The gas processing agreement requires that the processing plant be operational no later than November 1, 2015.

Classic Pipeline Gas Gathering Agreement & Water Disposal Agreement

On November 1, 2011, Classic Hydrocarbons Operating, LLC (Classic Operating) and Classic Pipeline entered into a gas gathering agreement. Pursuant to the gas gathering agreement, Classic Operating dedicated to Classic Pipeline all of the natural gas produced (up to 50,000 MMBtus per day) on the properties operated by Classic Operating within certain counties in Texas through 2020, subject to one-year extensions at either party s election. On May 1, 2014, Classic Operating and Classic Pipeline amended the gas gathering agreement with respect to Classic Operating s remaining assets located in Panola and Shelby Counties, Texas. Under the amended gas gathering agreement, Classic Operating agreed to pay a fee of (i) $0.30 per MMBtu, subject to an annual 3.5% inflationary escalation, based on volumes of natural gas delivered and processed, and (ii) $0.07 per MMBtu per stage of compression plus its allocated share of compressor fuel. The amended gas gathering agreement has a term until December 31, 2023, subject to one-year extensions at either party s election.

On May 1, 2014, Classic Operating and Classic Pipeline entered into a water disposal agreement. The water disposal agreement has a three-year term, subject to one-year extensions at either party s election. Under the water disposal agreement, Classic Operating agreed to pay a fee of $1.10 per barrel for each barrel of water delivered to Classic Pipeline.

Propel Purchase and Sale Agreement

On October 1, 2013, the Partnership purchased certain oil and natural gas properties from Propel Energy, LLC (Propel) pursuant to that certain Purchase and Sale Agreement between Memorial Production Operating LLC, the Partnership s wholly-owned subsidiary, and Propel. The consideration paid by the Partnership to Propel for the assets was approximately $80 million. At the time of the transaction, William J. Scarff was president and chief executive officer of Propel. Mr. Scarff s indirect interest in the transaction was approximately $1,016,000.

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Repurchase of Net Profits Interests

On February 28, 2014, WildHorse Resources repurchased net profits interests from an affiliate of NGP for $63.4 million after customary adjustments. These net profits interests were originally sold to the NGP affiliate upon the completion of certain acquisitions in 2010 by WildHorse Resources.

Dispositions of Oil and Natural Gas Producing Properties to the Partnership

We have divested long-lived producing oil and natural gas properties to the Partnership through the following drop down transactions:

- In April 2012, we sold 22 Bcfe of proved reserves located in East Texas to the Partnership for cash consideration of approximately $18.5 million;
- In May 2012, we sold an additional 28 Bcfe of proved reserves in East Texas to the Partnership for a final purchase price of approximately $27.0 million;
- In March 2013, we sold 162 Bcfe of proved reserves located in East Texas to the Partnership for cash consideration of approximately $200.0 million;
- In October 2013, we sold 99 Bcfe of proved reserves located in East Texas and the Rocky Mountains to the Partnership for cash consideration of approximately $96.3 million;
- In April 2014, we sold approximately 15 Bcfe of proved reserves located in East Texas to the Partnership for cash consideration of approximately $33.3 million, including estimated customary post-closing adjustments; and
- In October 2014, we sold 4.7 Bcfe of proved reserves located in Weld County, Colorado to the Partnership for cash consideration of approximately $15.0 million.

Procedures for Approval of Related Party Transactions

We maintain a policy for approval of related party transactions. A related party transaction is a transaction, arrangement or relationship in which we or any of our subsidiaries was, is or will be a participant, the amount of which involved exceeds $120,000, and in which any related person had, has or will have a direct or indirect material interest. A related person means:

- any person who is, or at any time during the applicable period was, one of our executive officers or one of our directors;

any person who is known by us to be the beneficial owner of more than 5% of our common stock;

any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law or sister-in-law of a director, executive officer or a beneficial owner of more than 5% of our common stock, and any person (other than a tenant or employee) sharing the household of such director, executive officer or beneficial owner of more than 5% of our common stock; and

any firm, corporation or other entity in which any of the foregoing persons is a partner or principal or in a similar position or in which such person has a 10% or greater beneficial ownership interest.

Pursuant to this policy, our Audit Committee reviews all material facts of all related party transactions.

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DESCRIPTION OF CAPITAL STOCK

Our authorized capital stock consists of 600,000,000 shares of common stock, $0.01 par value per share, of which 193,559,211 shares are issued and outstanding, and 50,000,000 shares of preferred stock, $0.01 par value per share, of which no shares are issued and outstanding.

The following summary of our capital stock, our amended and restated certificate of incorporation and our amended and restated bylaws do not purport to be complete and are qualified in their entirety by reference to the provisions of applicable law and to our amended and restated certificate of incorporation and amended and restated bylaws, copies of which are filed as exhibits to the registration statement of which this prospectus is a part.

Common Stock

Except as provided by law or in a preferred stock designation, holders of common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, will have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, holders of common stock are not entitled to vote on any amendment to the amended and restated certificate of incorporation (including any certificate of designations relating to any series of preferred stock) that relates solely to the terms of any outstanding series of preferred stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to the amended and restated certificate of incorporation (including any certificate of designations relating to any series of preferred stock) or pursuant to the DGCL. Subject to prior rights and preferences that may be applicable to any outstanding shares or series of preferred stock, holders of common stock are entitled to receive ratably in proportion to the shares of common stock held by them such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our Board out of funds legally available for dividend payments. All outstanding shares of common stock are fully paid and non-assessable, and the shares of common stock to be issued upon completion of the initial public offering will be fully paid and non-assessable. The holders of common stock have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to the common stock. In the event of any voluntary or involuntary liquidation, dissolution or winding-up of our affairs, holders of common stock will be entitled to share ratably in our assets in proportion to the shares of common stock held by them that are remaining after payment or provision for payment of all of our debts and obligations and after distribution in full of preferential amounts to be distributed to holders of outstanding shares of preferred stock, if any.

Preferred Stock

Our amended and restated certificate of incorporation authorizes our Board, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of preferred stock, par value $0.01 per share, covering up to an aggregate of 50,000,000 shares of preferred stock. Each class or series of preferred stock will cover the number of shares and will have the powers, preferences, rights, qualifications, limitations and restrictions determined by the Board, which may include, among others, dividend rights, liquidation preferences, voting rights, conversion rights, preemptive rights and redemption rights. Except as provided by law or in a preferred stock designation, the holders of preferred stock will not be entitled to vote at or receive notice of any meeting of stockholders.

Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, Our Amended and Restated Bylaws and Delaware Law

Some provisions of Delaware law and our amended and restated certificate of incorporation and our amended and restated bylaws contain provisions that could make the following transactions more difficult: acquisitions of us by means of a tender offer, a proxy contest or otherwise; or removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware Law

We are subject to the provisions of Section 203 of the DGCL, which regulates corporate takeovers. In general, those provisions prohibit a Delaware corporation, including those whose securities are listed for trading on the NASDAQ, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- the business combination or transaction in which the person became interested is approved by the Board before the date the interested stockholder attained that status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced other than, for purposes of determining the voting stock outstanding (but not the outstanding stock owned by the interested stockholder), shares owned by persons who are directors and also officers of us and by certain employee stock plans; or
- on or after such time the business combination is approved by the Board and authorized at a meeting of stockholders by at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

Section 203 defines business combination to include the following:

- certain mergers or consolidations involving the corporation and the interested stockholder;
- any sale, transfer, pledge or other disposition of 10% or more of the assets of the corporation to or with the interested stockholder;
- subject to certain exceptions, any transaction that results in the issuance or transfer by the corporation of any stock of the corporation to the interested stockholder;
- subject to certain exceptions, any transaction involving the corporation that has the effect of increasing the proportionate share of the stock of any class or series of the corporation beneficially owned by the interested stockholder; or

the receipt by the interested stockholder of the benefit of loans, advances, guarantees, pledges or other financial benefits provided by or through the corporation.

In general, Section 203 defines an interested stockholder as any entity or person beneficially owning 15% or more of the outstanding voting stock of the corporation and any entity or person affiliated with or controlling or controlled by any of these entities or persons. Since the Funds will have owned their equity in us at the time we complete our corporate formation, the Funds will not be subject to the restrictions of Section 203.

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Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws

Provisions of our amended and restated certificate of incorporation and amended and restated bylaws may delay or discourage transactions involving an actual or potential change in control or change in our management, including transactions in which stockholders might otherwise receive a premium for their shares, or transactions that our stockholders might otherwise deem to be in their best interests. Therefore, these provisions could adversely affect the price of our common stock.

Among other things, our amended and restated certificate of incorporation and amended and restated bylaws:

- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 90 days nor more than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Our amended and restated bylaws specify the requirements as to form and content of all stockholders notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

- provide our Board the ability to authorize undesignated preferred stock. This ability makes it possible for our Board to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These and other provisions may have the effect of deferring hostile takeovers or delaying changes in control or management of our company;

- provide that the authorized number of directors may be changed only by an affirmative vote of a majority of the total number of authorized directors whether or not there exist any vacancies in previously authorized directorships;

- provide that all vacancies, including newly created directorships, may, except as otherwise required by law or, if applicable, the rights of holders of a series of preferred stock then outstanding, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;

- at any time after a group including MRD Holdco and/or the Funds or their respective affiliates no longer collectively beneficially own more than 50% of the outstanding shares of our common stock:

- provide that any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of preferred stock with respect to such series (prior to such time, such actions may be taken without a meeting by written consent of holders of common stock having not less than the minimum number of votes that would be necessary to authorize such action at a meeting);

- provide our certificate of incorporation and bylaws, subject to certain exceptions, may be amended by the affirmative vote of the holders of not less than 66 2/3% of our then outstanding common stock (prior to such time, our certificate of incorporation and bylaws may be amended by the affirmative vote of the holders of not less than 50% majority of our then outstanding common stock);

- provide that special meetings of our stockholders may only be called by the Board pursuant to a resolution adopted by the affirmative vote of a majority of the total number of directors whether or not there exist any vacancies in previously authorized directorships, (prior to such time, a special meeting may also be called at the request of stockholders holding a majority of the outstanding shares entitled to vote);

provide for our Board to be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms, other than directors which may be elected by holders of preferred stock, if any, and that directors may only be removed for cause. This system of

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electing and removing directors may tend to discourage a third party from making a tender offer or otherwise attempting to obtain control of us, because it generally makes it more difficult for stockholders to replace a majority of the directors; and

provide that the affirmative vote of the holders of at least 75% in voting power of all then outstanding common stock entitled to vote generally in the election of directors, voting together as a single class, shall be required to remove any or all of the directors from office and such removal may only be for cause.

Limitation of Liability and Indemnification Matters

Our amended and restated certificate of incorporation limits the liability of our directors for monetary damages for breach of their fiduciary duty as directors, except for liability that cannot be eliminated under the DGCL. Delaware law provides that directors of a company will not be personally liable for monetary damages for breach of their fiduciary duty as directors, except for liabilities:

for any breach of their duty of loyalty to us or our stockholders;

for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;

for unlawful payment of dividend or unlawful stock repurchase or redemption, as provided under Section 174 of the DGCL; or

for any transaction from which the director derived an improper personal benefit.

Any amendment, repeal or modification of these provisions will be prospective only and would not affect any limitation on liability of a director for acts or omissions that occurred prior to any such amendment, repeal or modification.

Our amended and restated certificate of incorporation and amended and restated bylaws also provide that we will indemnify our directors and officers to the fullest extent permitted by Delaware law. In connection with the closing of our initial public offering, we entered into indemnification agreements with each of our directors and officers. These agreements require us to indemnify these individuals to the fullest extent permitted under Delaware law against liability that may arise by reason of their service to us, and to advance expenses incurred as a result of any proceeding against them as to which they could be indemnified. We believe that the limitation of liability provision in our amended and restated certificate of incorporation and the indemnification agreements facilitates our ability to continue to attract and retain qualified individuals to serve as directors and officers.

Corporate Opportunity

Under our amended and restated certificate of incorporation, to the fullest extent permitted by law:

MRD Holdco, NGP, the Funds and their affiliates have the right to, and have no duty to abstain from, exercising such right to, conduct business with any business that is competitive or in the same line of business as us, do business with any of our clients or customers, or invest or own any interest publicly or privately in, or develop a business relationship with, any business that is competitive or in the same line of business as us;

if MRD Holdco, NGP, the Funds or their affiliates acquires knowledge of a potential transaction that could be a corporate opportunity, they have no duty to offer such corporate opportunity to us; and

we have renounced any interest or expectancy in, or in being offered an opportunity to participate in, such corporate opportunities.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is Wells Fargo Shareowner Services.

Listing

Our common stock is listed on the NASDAQ Global Select Market under the symbol MRD.

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SHARES ELIGIBLE FOR FUTURE SALE

No predictions can be made about the effect, if any, that market sales of shares of our common stock or the availability of such shares for sale will have on the market price prevailing from time to time. Nevertheless, the actual sale of, or the perceived potential for the sale of, our common stock in the public market may have an adverse effect on the market price for our common stock and could impair our ability to raise capital through future sales of our securities. See Risk Factors Risks Related to This Offering Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Sale of Restricted Shares

As of November 1, 2014, 193,559,211 shares of our common stock were outstanding, which number will not change as a result of this offering. All of the shares of our common stock to be sold in this offering will be freely tradable without restriction or further registration under the Securities Act, except for any shares which may be acquired by any of our affiliates as that term is defined in Rule 144 under the Securities Act, which will be subject to the resale limitations of Rule 144. The remaining shares of our common stock outstanding will be restricted securities, as that term is defined in Rule 144, and may in the future be sold pursuant to an effective registration statement or under the Securities Act to the extent permitted by Rule 144 or any other available exemption under the Securities Act. All of the remaining shares beneficially owned by MRD Holdco and certain former management members of WildHorse Resources following this offering will be restricted securities.

Memorial Resource Development Corp. 2014 Long Term Incentive Plan

We have filed a registration statement on Form S-8 under the Securities Act with the SEC covering 19,250,000 shares of our common stock issued or reserved for issuance under the Memorial Resource Development Corp. 2014 Long Term Incentive Plan. Subject to the expiration of any lock-up restrictions as described below and following the completion of any vesting periods, shares of our common stock issued under the Memorial Resource Development Corp. 2014 Long Term Incentive Plan, issuable upon the exercise of options granted or to be granted under the plan, will be freely tradable without restriction under the Securities Act, unless such shares are held by any of our affiliates.

Lock-up Agreements

We, our executive officers and directors, the selling stockholders and WHR Incentive LLC, a limited liability company beneficially owned by Messrs. Anthony Bahr and Jay Graham, have agreed not to sell or transfer any shares of our common stock for a period of 60 days from the date of this prospectus, subject to certain exceptions and extensions. See Underwriting for a description of these lock-up provisions.

Rule 144

In general, under Rule 144 under the Securities Act, a person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months (including any period of consecutive ownership of preceding non-affiliated holders) would be entitled to sell those shares. A non-affiliated person who has beneficially owned restricted securities within the meaning of Rule 144 for at least one year would be entitled to sell those shares without regard to the provisions of Rule 144.

A person who is deemed to be an affiliate of ours and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months would be entitled to sell within any three-month period a number of shares (when aggregated with sales by certain related parties) that does not exceed the greater of 1%

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of the then outstanding shares of our common stock (193,559,211 shares following this offering) or the average weekly trading volume of our common stock reported through the applicable stock exchange during the four calendar weeks preceding such sale. Such sales are also subject to certain manner of sale provisions, notice requirements and the availability of current public information about us.

Registration Rights

Pursuant to the Registration Rights Agreement, MRD Holdco and certain former management members of WildHorse Resources, Jay Graham and Anthony Bahr, have customary rights to demand that we file a resale shelf registration statement or, in certain circumstances, conduct an underwritten offering of shares held by MRD Holdco, Jay Graham and Anthony Bahr. In addition, the agreement grants MRD Holdco, Jay Graham and Anthony Bahr customary rights to participate in certain underwritten offerings of our common stock that we may conduct. See Certain Relationships and Related Party Transactions Registration Rights Agreement.

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MATERIAL TAX CONSEQUENCES

TO

NON-U.S. HOLDERS

Introduction

The following is a discussion of certain U.S. federal income tax considerations applicable to Non-U.S. Holders (as defined below) arising from the acquisition, ownership and disposition of shares of our common stock. This summary is for general information purposes only and does not purport to be a complete analysis or listing of all potential U.S. federal income tax considerations that may apply to a Non-U.S. Holder as a result of the acquisition, ownership and disposition of shares of our common stock. In addition, this summary does not take into account the individual facts and circumstances of any particular Non-U.S. Holder that may affect the U.S. federal income tax considerations applicable to such holder. Accordingly, this summary is not intended to be, and should not be construed as, legal or U.S. federal income tax advice with respect to any Non-U.S. Holder. Moreover, this summary is not binding on the Internal Revenue Service, or the IRS, or the U.S. courts, and no assurance can be provided that the conclusions reached in this summary will not be challenged by the IRS or will be sustained by a U.S. court if so challenged. We have not requested, and we do not intend to request, a ruling from the IRS or an opinion from U.S. legal counsel regarding any of the U.S. federal income or other tax considerations of the acquisition, ownership and disposition of shares of our common stock. Each Non-U.S. Holder should consult its own tax advisor regarding the acquisition, ownership and disposition of shares of our common stock.

Scope of This Disclosure

Authorities

This summary is based on the Internal Revenue Code of 1986, as amended (the Code), Treasury Regulations (final, temporary, and proposed), U.S. court decisions, published IRS rulings and published administrative positions of the IRS, that are applicable and, in each case, as in effect and available, as of the date of this prospectus. Any of the authorities on which this summary is based could be changed in a material and adverse manner at any time, and any such change could be applied on a retroactive basis and could affect the U.S. federal income tax considerations described in this summary.

Non-U.S. Holders

For purposes of this summary, a Non-U.S. Holder is a beneficial owner of shares of our common stock that is not a partnership or other entity classified as a partnership for U.S. federal income tax purposes and that is not: (a) an individual who is a citizen or resident of the U.S., (b) a corporation, or other entity classified as a corporation for U.S. federal income tax purposes, that is created or organized in or under the laws of the U.S. or any state in the U.S., including the District of Columbia, (c) an estate if the income of such estate is subject to U.S. federal income tax regardless of the source of such income, or (d) a trust if (i) such trust has validly elected to be treated as a U.S. person for U.S. federal income tax purposes or (ii) a U.S. court is able to exercise primary supervision over the administration of such trust and one or more U.S. persons have the authority to control all substantial decisions of such trust.

Non-U.S. Holders Subject to Special U.S. Federal Income Tax Rules Not Addressed

This summary does not address the U.S. federal income tax considerations of the acquisition, ownership and disposition of shares of our common stock by Non-U.S. Holders that are subject to special provisions under the Code, including the following Non-U.S. Holders: (a) Non-U.S. Holders that are tax-exempt organizations, qualified retirement plans, individual retirement accounts, or other tax-deferred accounts; (b) Non-U.S. Holders that are financial institutions, insurance companies, real estate investment trusts, or regulated investment companies or that are broker-dealers, dealers, or traders in securities or currencies that elect to apply a mark-to-market accounting method; (c) Non-U.S. Holders that have a functional currency other than the U.S. dollar;

(d) Non-U.S. Holders that own shares of our common stock as part of a straddle, hedging transaction, conversion transaction, constructive sale, or other arrangement involving more than one position; (e) Non-U.S. Holders that acquire shares of our common stock in connection with the exercise of employee stock options or otherwise as compensation for services; (f) Non-U.S. Holders that hold shares of our common stock other than as a capital asset within the meaning of Section 1221 of the Code; (g) Non-U.S. Holders who are U.S. expatriates or former long term residents of the United States; and (h) Non-U.S. Holders that have or now own, directly, indirectly, or by attribution, 5% or more, by voting power or value, of the outstanding shares of our common stock. Non-U.S. Holders that are subject to special provisions under the Code, including but not limited to Non-U.S. Holders described immediately above, should consult their own tax advisors regarding the U.S. federal, U.S. state and local, and foreign tax and other tax considerations of the acquisition, ownership and disposition of shares of our common stock.

If a partnership or other entity that is classified as a partnership for U.S. federal income tax purposes holds shares of our common stock, the U.S. federal income tax considerations to such partnership and the partners of such partnership generally will depend on the activities of the partnership and the status of such partners (or owners). Partnerships or other entities that are classified as partnerships for U.S. federal income tax purposes and their owners should consult their own tax advisors regarding the U.S. federal income tax considerations of the acquisition, ownership and disposition of shares of our common stock.

Tax Considerations Other Than U.S. Federal Income Tax Considerations Not Addressed

This summary does not address any state, local, alternative minimum, estate and gift, foreign, or other tax considerations other than U.S. federal income tax considerations that may be relevant to Non-U.S. Holders in connection with the acquisition, ownership and disposition of shares of our common stock. Each Non-U.S. Holder should consult its own tax advisors regarding any state, local, estate and gift, foreign, and any other tax considerations that may be relevant to such holder in connection with the acquisition, ownership and disposition of shares of our common stock.

Dividends

In general, if dividends with respect to shares of our common stock are made, such dividends would be treated as dividends to the extent of our current or accumulated earnings and profits as determined under the Code. Any portion of a dividend that exceeds our current or accumulated earnings and profits will first be applied to reduce the Non-U.S. Holder s basis in shares of our common stock, and, to the extent such portion exceeds the Non-U.S. Holder s basis, the excess will be treated as gain from the disposition of shares of our common stock, the tax treatment of which is discussed below under the heading Gain on Sale or Other Disposition of Shares of our Common Stock.

Generally, dividends paid in respect of shares of our common stock to a Non-U.S. Holder will be subject to U.S. withholding tax at a 30% rate, subject to the two following exceptions:

Dividends effectively connected with a trade or business of a Non-U.S. Holder within the U.S. generally will not be subject to withholding if the Non-U.S. Holder complies with applicable IRS certification and disclosure requirements and generally will be subject to U.S. federal income tax on a net income basis at regular U.S. federal income tax rates (in the same manner as a U.S. person) on its U.S. trade or business income. In the case of a Non-U.S. Holder that is a corporation, such effectively connected income also may be subject to the branch profits tax at a 30% rate (or such lower rate as may be prescribed by an applicable tax treaty).

The withholding tax might not apply, or might apply at a reduced rate, under the terms of an applicable tax treaty. Under Treasury Regulations, to obtain a reduced rate of withholding under a tax treaty, a Non-U.S. Holder generally will be required to satisfy applicable certification and other requirements. A Non-U.S. Holder of shares of our common stock eligible for a reduced rate of U.S. withholding tax may obtain a refund or credit of any excess amounts withheld by filing an appropriate claim for refund with the IRS.

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Gain on Sale or Other Disposition of Shares of Our Common Stock

Except as described in the discussion below under the heading Information Reporting; Backup Withholding Tax, a Non-U.S. Holder generally will not be subject to U.S. federal income tax, including withholding tax, in connection with the receipt of proceeds from the sale, exchange, or other taxable disposition of shares of our common stock, unless:

- the gain is effectively connected with the Non-U.S. Holder s conduct of a trade or business within the United States and, if subject to an applicable tax treaty, is attributable to a permanent establishment or fixed base maintained by the Non-U.S. Holder in the U.S.;
- in the case of an individual, the Non-U.S. Holder has been present in the U.S. for at least 183 days or more in the taxable year of disposition (and certain other conditions are satisfied); or
- we are or have been a U.S. real property holding corporation, or USRPHC, for U.S. federal income tax purposes (that is, a domestic corporation whose trade or business and real property assets consist primarily of U.S. real property interests) at any time during the shorter of the five-year period ending on the date of disposition and the Non-U.S. Holder s holding period for its shares of our common stock and, if shares of our common stock are regularly traded on an established securities market, the Non-U.S. Holder held, directly or indirectly, at any time during such period, more than 5% of our issued and outstanding common stock.

Income that is effectively connected with the conduct of a U.S. trade or business by a Non-U.S. Holder generally will be subject to regular U.S. federal income tax in the same manner as if it were realized by a U.S. Holder. In addition, if such Non-U.S. Holder is a corporation, such gain may be subject to a branch profits tax at a rate of 30% (or such lower rate as is provided by an applicable income tax treaty).

If an individual Non-U.S. Holder is present in the U.S. for at least 183 days during the taxable year of disposition, the Non-U.S. Holder may be subject to a flat 30% tax on any U.S.-source gain derived from the sale, exchange, or other taxable disposition of shares of our common stock (other than gain effectively connected with a U.S. trade or business), which may be offset by U.S.-source capital losses.

It is likely that we will be a USRPHC. As a result, any gain recognized by a Non-U.S. Holder on the sale, exchange, or other taxable disposition of our common stock may be subject to U.S. federal income tax in the same manner as gain recognized by a U.S. Holder, or the FIRPTA Tax. In addition, a Non-US. Holder may under certain circumstances be subject to withholding in an amount equal to 10% of the gross proceeds on the sale or disposition; if the Non-U.S. Holder files a U.S. federal income tax return, any amounts so withheld will generally be credited against, and refunded to the extent in excess of, any FIRPTA Tax such Non-U.S. Holder owes.

However, so long as our common stock is considered to be regularly traded on an established securities market, or regularly traded, at any time during the calendar year, a Non-U.S. Holder generally will not be subject to FIRPTA Tax on any gain recognized on the sale or other disposition of our common stock unless the Non-U.S. Holder owned (actually or constructively) shares of our common stock with a fair market value of more than 5% of the total fair market value of our common stock at any time during the applicable period described in the third bullet point above. No withholding is required under these rules upon a sale or other taxable disposition of our common stock if it is considered to be regularly traded. If, on the other hand, our common stock is not considered to be regularly traded, a Non-U.S. Holder will be subject to FIRPTA Tax on any gain recognized on your sale or other taxable disposition of our common stock, and withholding on the gross proceeds thereof, regardless of such Non-U.S. Holder s percentage ownership of our common stock.

Foreign Account Tax Compliance Act

Legislation enacted in 2010 and recent administrative guidance will require withholding at a rate of 30% on dividends paid on or after July 1, 2014 (and gross proceeds from the sale of shares of our common stock paid on or after January 1, 2017) to certain foreign financial institutions (including investment funds), unless such

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institution enters into an agreement with the Secretary of the Treasury to, among other things, report, on an annual basis, information with respect to accounts with or shares in the institution held by certain U.S. persons and by certain non-U.S. entities that are wholly or partially owned by United States persons, and to withhold on payments made to certain account holders. Accordingly, the entity through which shares of our common stock is held will affect the determination of whether such withholding is required. Similarly, dividends in respect of, and gross proceeds from the sale of, shares of our common stock held by an investor that is a non-financial foreign entity will be subject to withholding at a rate of 30% if such entity or another non-financial foreign entity is the beneficial owner of the payment, unless, among other things, the beneficial owner or the payee either (i) certifies to the withholding agent that such entity does not have any substantial United States owners or (ii) provides certain information regarding the entity s substantial United States owners to the withholding agent, which the withholding agent will in turn provide to the Secretary of the Treasury. Non-U.S. holders are encouraged to consult with their tax advisors regarding the possible implications of the legislation on their investment in shares of our common stock.

Information Reporting; Backup Withholding Tax

A Non-U.S. Holder generally will not be subject to information reporting or backup withholding with respect to payments of dividends on, or gross proceeds from the disposition of, shares of our common stock that are made within the United States or though certain U.S.-related financial intermediaries, provided that the Non-U.S. Holder certifies as to its foreign status or otherwise establishes an exemption.

Backup withholding is not an additional tax. Amounts withheld as backup withholding may be credited against a Non-U.S. Holder s U.S. federal income tax liability, and a Non-U.S. Holder may obtain a refund of any excess amounts withheld under the backup withholding rules by timely filing the appropriate claim for refund with the IRS and furnishing any required information. Non-U.S. Holders should consult their own tax advisors regarding the application of the information reporting and backup withholding rules to them in their particular circumstances.

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UNDERWRITING

Citigroup Global Markets Inc. and Barclays Capital Inc. are acting as the representatives of the underwriters named below, and Citigroup Global Markets Inc., Barclays Capital Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, BMO Capital Markets Corp., Goldman, Sachs & Co., J.P. Morgan Securities LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC and Wells Fargo Securities, LLC are acting as joint book-running managers of this offering. Subject to the terms and conditions stated in the underwriting agreement dated the date of this prospectus, each underwriter named below has severally agreed to purchase, and the selling stockholders have agreed to sell to that underwriter, the number of shares set forth opposite the underwriter s name.

Underwriter	Number of Shares
Citigroup Global Markets Inc.	6,000,000
Barclays Capital Inc.	4,500,000
Merrill Lynch, Pierce, Fenner & Smith Incorporated	2,100,000
BMO Capital Markets Corp.	2,100,000
Goldman, Sachs & Co.	2,100,000
J.P. Morgan Securities LLC	2,100,000
Raymond James & Associates, Inc.	2,100,000
RBC Capital Markets, LLC	2,100,000
Wells Fargo Securities, LLC	2,100,000
Credit Suisse Securities (USA) LLC	687,000
Scotia Capital (USA) Inc.	687,000
Simmons & Company International	687,000
Stephens Inc.	687,000
Stifel, Nicolaus & Company, Incorporated	687,000
Wunderlich Securities, Inc.	687,000
Credit Agricole Securities (USA) Inc.	339,000
Natixis Securities Americas LLC	339,000
Total	30,000,000

The underwriting agreement provides that the obligations of the underwriters to purchase the shares included in this offering are subject to approval of legal matters by counsel and to other conditions. The underwriters are obligated to purchase all the shares (other than those covered by the underwriters option to purchase additional shares described below) if they purchase any of the shares.

Shares sold by the underwriters to the public will initially be offered at the public offering price set forth on the cover of this prospectus. Any shares sold by the underwriters to securities dealers may be sold at a discount from the public offering price not to exceed $0.4485 per share. If all the shares are not sold at the public offering price, the underwriters may change the offering price and the other selling terms. The offering of the shares by the underwriters is subject to receipt and acceptance and subject to the underwriters right to reject any order in whole or in part. The representative has advised us that the underwriters do not intend to make sales to discretionary accounts.

If the underwriters sell more shares than the total number set forth in the table above, the selling stockholders have granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to 4,500,000 additional shares at the public offering price less the underwriting discount. To the extent the option is exercised, each underwriter must purchase a number of additional shares approximately proportionate to that underwriter s initial purchase commitment. Any shares issued or sold under the option will be issued and sold on the same terms and conditions as the other shares that are the subject of this offering.

We, our officers and directors, the selling stockholders and WHR Incentive LLC, a limited liability company beneficially owned by Messrs. Bahr and Graham, have agreed that, for a period of 60 days from the date of this prospectus, we and they will not, without the prior written consent of Citigroup Global Markets Inc. dispose of or hedge any shares or any securities convertible into or exchangeable for our common stock. Citigroup Global Markets Inc. in its sole discretion may release any of the securities subject to these lock-up agreements at any time, which, in the case of officers and directors, shall be with notice.

The offering price for the shares will be determined by negotiations among the selling stockholders and the representative. Among the factors considered in determining the offering price are our results of operations, our current financial condition, our future prospects, our markets, the economic conditions in and future prospects for the industry in which we compete, our management, and currently prevailing general conditions in the equity securities markets, including current market valuations of publicly traded companies considered comparable to our company. We cannot assure you, however, that the price at which the shares will sell in the public market after this offering will not be lower than the public offering price or that an active trading market in our shares will continue after this offering.

Our shares are listed on the Nasdaq Global Select Market under the symbol MRD.

The following table shows the underwriting discounts and commissions that we and the selling stockholders are to pay to the underwriters in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters option to purchase additional shares of common stock.

	Paid by the Selling Stockholders	
	No Exercise	**Full Exercise**
Per share	$ 0.7475	$ 0.7475
Total	$ 22,425,000	$ 25,788,750

We estimate that our portion of the total expenses of this offering will be approximately $0.9 million (excluding underwriting discounts and commissions). We have also agreed to reimburse the underwriters for certain of their expenses in an amount up to $10,000.

In connection with the offering, the underwriters may purchase and sell shares in the open market. Purchases and sales in the open market may include short sales, purchases to cover short positions, which may include purchases pursuant to the underwriters option to purchase additional shares, and stabilizing purchases.

Short sales involve secondary market sales by the underwriters of a greater number of shares than they are required to purchase in the offering.

Covered short sales are sales of shares in an amount up to the number of shares represented by the underwriters option to purchase additional shares.

Naked short sales are sales of shares in an amount in excess of the number of shares represented by the underwriters option to purchase additional shares.

Covering transactions involve purchases of shares either pursuant to the underwriters option to purchase additional shares or in the open market in order to cover short positions.

To close a naked short position, the underwriters must purchase shares in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.

To close a covered short position, the underwriters must purchase shares in the open market or must exercise their option to purchase additional shares. In determining the source of shares to close the covered short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through the underwriters option to purchase additional shares.

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Stabilizing transactions involve bids to purchase shares so long as the stabilizing bids do not exceed a specified maximum.

Purchases to cover short positions and stabilizing purchases, as well as other purchases by the underwriters for their own accounts, may have the effect of preventing or retarding a decline in the market price of the shares. They may also cause the price of the shares to be higher than the price that would otherwise exist in the open market in the absence of these transactions. The underwriters may conduct these transactions on the Nasdaq Global Select Market, in the over-the-counter market or otherwise. If the underwriters commence any of these transactions, they may discontinue them at any time.

Relationships

The underwriters are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. The underwriters and their respective affiliates have in the past performed commercial banking, investment banking and advisory services for us from time to time for which they have received customary fees and reimbursement of expenses and may, from time to time, engage in transactions with and perform services for us in the ordinary course of their business for which they may receive customary fees and reimbursement of expenses. In connection with our initial public offering in June 2014, each of Citigroup Global Markets Inc., Barclays Capital Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, BMO Capital Markets Corp., Goldman, Sachs & Co., J.P. Morgan Securities LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC, Wells Fargo Securities, LLC, Credit Suisse Securities (USA) LLC, Scotia Capital (USA) Inc., Simmons & Company International, Stephens Inc., Stifel, Nicolaus & Company, Incorporated and Wunderlich Securities, Inc. acted as an underwriter and received customary fees for such service. In connection with our offering of senior notes in July 2014, each of Citigroup Global Markets Inc., Barclays Capital Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, BMO Capital Markets Corp., RBC Capital Markets, LLC, Wells Fargo Securities, LLC, Credit Agricole Securities (USA) Inc. and Natixis Securities Americas LLC acted as an initial purchaser and received customary fees for such service. In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (which may include bank loans and/or credit default swaps) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments. Such investments and securities activities may involve securities and/or instruments of ours or our affiliates. In addition, affiliates of each of Citigroup Global Markets Inc., Barclays Capital Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, BMO Capital Markets Corp., J.P. Morgan Securities LLC, RBC Capital Markets, LLC, Wells Fargo Securities, LLC, Credit Agricole Securities (USA) Inc. and Natixis Securities Americas LLC are agents or lenders under our revolving credit facility. Certain of the underwriters or their affiliates that have a lending relationship with us routinely hedge their credit exposure to us consistent with their customary risk management policies. A typical such hedging strategy would include these underwriters or their affiliates hedging such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities. The underwriters and their affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or financial instruments and may hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

We and the selling stockholders have agreed to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act, or to contribute to payments the underwriters may be required to make because of any of those liabilities.

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Notice to Prospective Investors in the European Economic Area

In relation to each member state of the European Economic Area that has implemented the Prospectus Directive (each, a relevant member state), with effect from and including the date on which the Prospectus Directive is implemented in that relevant member state (the relevant implementation date), an offer of shares described in this prospectus may not be made to the public in that relevant member state other than:

- to any legal entity which is a qualified investor as defined in the Prospectus Directive;

- to fewer than 100 or, if the relevant member state has implemented the relevant provision of the 2010 PD Amending Directive, 150 natural or legal persons (other than qualified investors as defined in the Prospectus Directive), as permitted under the Prospectus Directive, subject to obtaining the prior consent of the relevant Dealer or Dealers nominated by us for any such offer; or

- in any other circumstances falling within Article 3(2) of the Prospectus Directive,

provided that no such offer of shares shall require us or any underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Directive.

For purposes of this provision, the expression an offer of securities to the public in any relevant member state means the communication in any form and by any means of sufficient information on the terms of the offer and the shares to be offered so as to enable an investor to decide to purchase or subscribe for the shares, as the expression may be varied in that member state by any measure implementing the Prospectus Directive in that member state, and the expression Prospectus Directive means Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the relevant member state) and includes any relevant implementing measure in the relevant member state. The expression 2010 PD Amending Directive means Directive 2010/73/EU.

The sellers of the shares have not authorized and do not authorize the making of any offer of shares through any financial intermediary on their behalf, other than offers made by the underwriters with a view to the final placement of the shares as contemplated in this prospectus. Accordingly, no purchaser of the shares, other than the underwriters, is authorized to make any further offer of the shares on behalf of the sellers or the underwriters.

Notice to Prospective Investors in the United Kingdom

This prospectus is only being distributed to, and is only directed at, persons in the United Kingdom that are qualified investors within the meaning of Article 2(1)(e) of the Prospectus Directive that are also (i) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the Order) or (ii) high net worth entities, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order (each such person being referred to as a relevant person). This prospectus and its contents are confidential and should not be distributed, published or reproduced (in whole or in part) or disclosed by recipients to any other persons in the United Kingdom. Any person in the United Kingdom that is not a relevant person should not act or rely on this document or any of its contents.

Notice to Prospective Investors in France

Neither this prospectus nor any other offering material relating to the shares described in this prospectus has been submitted to the clearance procedures of the *Autorité des Marchés Financiers* or of the competent authority of another member state of the European Economic Area and notified to the *Autorité des Marchés Financiers.* The shares have not been offered or sold and will not be offered or sold, directly or indirectly, to the public in France. Neither this prospectus nor any other offering material relating to the shares has been or will be:

- released, issued, distributed or caused to be released, issued or distributed to the public in France; or
- used in connection with any offer for subscription or sale of the shares to the public in France.

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Such offers, sales and distributions will be made in France only:

- to qualified investors *(investisseurs qualifiés)* and/or to a restricted circle of investors *(cercle restreint d investisseurs)*, in each case investing for their own account, all as defined in, and in accordance with articles L.411-2, D.411-1, D.411-2, D.734-1, D.744-1, D.754-1 and D.764-1 of the French *Code monétaire et financier*;

- to investment services providers authorized to engage in portfolio management on behalf of third parties; or

- in a transaction that, in accordance with article L.411-2-II-1°-or-2°-or 3° of the French *Code monétaire et financier* and article 211-2 of the General Regulations *(Règlement Général)* of the *Autorité des Marchés Financiers,* does not constitute a public offer *(appel public à l épargne*).

The shares may be resold directly or indirectly, only in compliance with articles L.411-1, L.411-2, L.412-1 and L.621-8 through L.621-8-3 of the French *Code monétaire et financier*.

Notice to Prospective Investors in Hong Kong

The shares may not be offered or sold in Hong Kong by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap. 32, Laws of Hong Kong), or (ii) to professional investors within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a prospectus within the meaning of the Companies Ordinance (Cap. 32, Laws of Hong Kong) and no advertisement, invitation or document relating to the shares may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to shares which are or are intended to be disposed of only to persons outside Hong Kong or only to professional investors within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

Notice to Prospective Investors in Japan

The shares offered in this prospectus have not been and will not be registered under the Financial Instruments and Exchange Law of Japan. The shares have not been offered or sold and will not be offered or sold, directly or indirectly, in Japan or to or for the account of any resident of Japan (including any corporation or other entity organized under the laws of Japan), except (i) pursuant to an exemption from the registration requirements of the Financial Instruments and Exchange Law and (ii) in compliance with any other applicable requirements of Japanese law.

Notice to Prospective Investors in Singapore

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the shares may not be circulated or distributed, nor may the shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the SFA), (ii) to a relevant person pursuant to Section 275(1), or any person pursuant to Section 275(1A), and in accordance with the conditions specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA, in each case subject to compliance with conditions set forth in the SFA.

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Where the shares are subscribed or purchased under Section 275 of the SFA by a relevant person which is:

a corporation (which is not an accredited investor (as defined in Section 4A of the SFA)) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or

a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary of the trust is an individual who is an accredited investor,

shares, debentures and units of shares and debentures of that corporation or the beneficiaries rights and interest (howsoever described) in that trust shall not be transferred within six months after that corporation or that trust has acquired the shares pursuant to an offer made under Section 275 of the SFA except:

to an institutional investor (for corporations, under Section 274 of the SFA) or to a relevant person defined in Section 275(2) of the SFA, or to any person pursuant to an offer that is made on terms that such shares, debentures and units of shares and debentures of that corporation or such rights and interest in that trust are acquired at a consideration of not less than $200,000 (or its equivalent in a foreign currency) for each transaction, whether such amount is to be paid for in cash or by exchange of securities or other assets, and further for corporations, in accordance with the conditions specified in Section 275 of the SFA;

where no consideration is or will be given for the transfer; or

where the transfer is by operation of law.

Notice to Prospective Investors in Switzerland

The prospectus does not constitute an issue prospectus pursuant to Article 652a or Article 1156 of the Swiss Code of Obligations (CO) and the shares will not be listed on the SIX Swiss Exchange. Therefore, the prospectus may not comply with the disclosure standards of the CO and/or the listing rules (including any prospectus schemes) of the SIX Swiss Exchange. Accordingly, the shares may not be offered to the public in or from Switzerland, but only to a selected and limited circle of investors, which do not subscribe to the shares with a view to distribution.

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LEGAL MATTERS

The validity of the shares of common stock offered hereby will be passed upon for us by Akin Gump Strauss Hauer & Feld LLP, Houston, Texas. Certain legal matters in connection with this offering will be passed upon for the underwriters by Vinson & Elkins L.L.P., Houston, Texas.

EXPERTS

The consolidated and combined financial statements and schedules of our predecessor (as described in Note 1 to those financial statements) as of December 31, 2013 and 2012, and for each of the years then ended, have been included herein and in the registration statement in reliance upon the report of KPMG LLP, independent registered public accounting firm, appearing elsewhere herein, and upon the authority of said firm as experts in accounting and auditing.

The statements of revenues and direct operating expenses related to the properties acquired in the MEMP Wyoming Acquisition included in this prospectus and elsewhere in the registration statement have been so included in reliance upon the report of KPMG LLP, independent registered public accounting firm, upon authority of said firm as experts in accounting and auditing.

Estimated quantities of our proved oil and natural gas reserves and the net present value of such reserves as of December 31, 2013 and as of September 30, 2014 with respect to our Terryville Complex acreage set forth in this prospectus are based on the reserve reports prepared by Netherland, Sewell & Associates, Inc. Our acreage had been audited or evaluated by an independent reservoir engineering firm since 2011 and Netherland, Sewell & Associates, Inc. evaluated these reserves as of December 31, 2013 and September 30, 2014.

Our estimates of probable and possible reserves are prepared by management and audited by Netherland, Sewell & Associates, Inc.

Estimated quantities of MEMP s proved oil and natural gas reserves and the net present value of such reserves as of December 31, 2013 set forth in this prospectus are based on the reserve report prepared by Netherland, Sewell & Associates, Inc. MEMP s acreage had been audited or evaluated by an independent reservoir engineering firm since 2011 and Netherland, Sewell & Associates, Inc. evaluated these reserves as of December 31, 2013.

We have included these estimates in reliance on the authority of Netherland, Sewell & Associates, Inc. as experts in such matters.

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WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement under the Securities Act, with respect to the shares of our common stock offered by this prospectus. This prospectus, filed as a part of the registration statement, does not contain all of the information set forth in the registration statement or the exhibits and schedules thereto as permitted by the rules and regulations of the SEC. For further information about us and our common stock, you should refer to the registration statement. This prospectus summarizes provisions that we consider material of certain contracts and other documents to which we refer you. You should review the full text of those documents. We have included copies of those documents as exhibits to the registration statement. Our reports and other information that we have filed, or may in the future file, with the SEC are not incorporated by reference into and do not constitute part of this prospectus.

The registration statement and the exhibits thereto filed with the SEC may be inspected, without charge, and copies may be obtained at prescribed rates, at the public reference facility maintained by the SEC at 100 F Street, N.E., Washington, D.C. 20549. You may request copies of the documents, upon payment of a duplicating fee, by writing the Public Reference Section of the SEC. Please call 1-800-SEC-0330 for further information on the public reference rooms. Our filings with the SEC are also available to the public from commercial document retrieval services and at the web site maintained by the SEC at http://www.sec.gov.

Our website address is www.memorialrd.com. We expect to make available our periodic reports and other information filed with or furnished to the SEC, free of charge through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference herein and does not constitute a part of this prospectus.

We and our stockholders are subject to the proxy solicitation rules, annual and periodic reporting requirements and other requirements of the Exchange Act. These periodic reports, proxy statements and other information are available for inspection and copying at the regional offices, public reference facilities and web site of the SEC referred to above. We will furnish our stockholders with annual reports containing audited financial statements certified by an independent registered public accounting firm and quarterly reports containing unaudited financial statements for the first three quarters of each fiscal year.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

Introduction

We are a Delaware corporation (MRD) formed by Memorial Resource Development LLC (MRD LLC) in January 2014 to own and acquire oil and natural gas properties in North America. MRD LLC was a Delaware limited liability company formed on April 27, 2011 by Natural Gas Partners VIII, L.P. (NGP VIII), Natural Gas Partners IX, L.P. (NGP IX) and NGP IX Offshore Holdings, L.P. (NGP IX Offshore) (collectively, the Funds) to own, acquire, exploit and develop oil and natural gas properties. The Funds are private equity funds managed by Natural Gas Partners (NGP).

On June 18, 2014, we completed our initial public offering (IPO). In connection with the closing of our IPO, the Funds contributed all of their interests in MRD LLC to MRD Holdco LLC (MRD Holdco). MRD LLC and its consolidated subsidiaries, which is our accounting predecessor, contributed the following to us in exchange for shares of our common stock (which MRD LLC immediately distributed to MRD Holdco): (1) 100% of its ownership interests in Classic Hydrocarbons Holdings, L.P. (Classic), Classic Hydrocarbons GP Co., L.L.C. (Classic GP), Black Diamond Minerals, LLC (Black Diamond), Beta Operating Company, LLC (Beta Operating), MRD Operating LLC (MRD Operating) and Memorial Production Partners GP LLC (MEMP GP), which owns a 0.1% general partner interest and 50% of the incentive distribution rights in Memorial Production Partners LP (MEMP), and (2) its 99.9% membership interest in WildHorse Resources, LLC (WildHorse Resources). In addition, certain former management members of WildHorse Resources contributed to us the remaining 0.1% membership interest in WildHorse Resources as well as exchanged their incentive units in exchange for shares of our common stock and cash consideration. MRD LLC merged into MRD Operating on June 27, 2014 upon the discharge of the indenture governing the $350.0 million 10.00% / 10.75% Senior PIK toggle notes due 2018 (PIK notes). Prior to this merger, MRD LLC distributed the following to MRD Holdco: (i) its interests in BlueStone Natural Resources Holdings, LLC (BlueStone Holdings), Golden Energy Partners LLC (Golden Energy) and Classic Pipeline & Gathering, LLC (Classic Pipeline) as well as two immaterial subsidiaries that were formed subsequent to December 31, 2013, (ii) the MEMP subordinated units, (iii) the right to the remaining cash to be released from the debt service reserve account in connection with the redemption or earlier discharge of the PIK notes plus the cash received from us in reimbursement of the interest paid on June 15, 2014 in respect of the PIK notes and (iv) approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy Partners LLC s assets in May 2014. Collectively, we refer to these transactions as the Restructuring.

We control MEMP through our ownership of MEMP GP. MEMP is a publicly traded limited partnership engaged in the acquisition, production and development of oil and natural gas properties in the United States. Due to our control of MEMP through the ownership of its general partner, we are required to consolidate MEMP for accounting and financial reporting purposes.

We have two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

MRD reflects all of our consolidating subsidiaries except for MEMP and its subsidiaries.

MEMP reflects the consolidated and combined operations of MEMP and its subsidiaries.

On July 1, 2014, MEMP acquired certain oil producing properties and related facilities located in the Lost Soldier and Wertz fields in Wyoming from Merit Energy Company, LLC and certain of its affiliates (Merit Energy) for an adjusted purchase price of approximately $911.7 million, including estimated customary post-closing adjustments, with an effective date of April 1, 2014 (the Wyoming Acquisition).

On July 15, 2014, MEMP issued 9,890,000 common units representing limited partner interests in MEMP (including 1,290,000 common units purchased pursuant to the full exercise of the underwriters option to

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

purchase additional common units) to the underwriters at an offering price of $22.25 per unit generating total net proceeds of approximately $220.0 million after offering expenses. The net proceeds from the equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility. On September 9, 2014, MEMP issued 14,950,000 common units representing limited partner interests in MEMP (including 1,950,000 common units purchased pursuant to the full exercise of the underwriters option to purchase additional common units) to the public at an offering price of $22.29 per unit generating total net proceeds of approximately $321.6 million after deducting underwriting discounts of approximately $11.7 million and offering expenses. The net proceeds from the equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility. Collectively, we refer to these offerings as the MEMP Offerings.

On July 10, 2014, MRD completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes at par. On July 17, 2014, the MEMP completed a private placement of $500.0 million aggregate principal amount of 6.875% senior unsecured notes at 98.485% of par. Collectively, we refer to these offerings as the Debt Offerings.

The unaudited pro forma combined statements of operations of MRD is based on our audited and unaudited historical consolidated and combined statement of operations (including those of our predecessor) for the year ended December 31, 2013 and the nine months ended September 30, 2014, respectively, having been adjusted to give effect to the following transactions as if they had occurred on January 1, 2013 for pro forma statements of operations purposes:

- the exclusion of BlueStone Holdings and Classic Pipeline;
- the exclusion of the MEMP subordinated units;
- the Restructuring;
- the Wyoming Acquisition;
- the MEMP Offerings; and
- the Debt Offerings.

The unaudited pro forma combined financial statements should be read in conjunction with the notes thereto and with our historical financial statements (including those of our predecessor) and the historical financial statements of the Wyoming Acquisition, included elsewhere in this prospectus.

The actual effect of the transactions discussed in the accompanying notes ultimately may differ from the unaudited pro forma adjustments included herein. However, management believes that the assumptions utilized to prepare the pro forma adjustments provide a reasonable basis for presenting the significant effects of the transactions and that the unaudited pro forma adjustments are factually supportable, give appropriate effect to the impact of events that are directly attributable to the transactions, and reflect those items expected to have a continuing impact on MRD.

The unaudited pro forma combined financial statements of MRD are not necessarily indicative of financial results that would have been attained had the described transactions occurred on the dates indicated below or which could be achieved in the future because they necessarily exclude various operating expenses.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENTS OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2013

(in thousands, excepts per share amounts)	MRD LLC Historical	Exclude BlueStone Holdings & Classic Pipeline	Wyoming Acquisition Historical	Other Pro Forma Adjustments	MRD Pro Forma Combined
Revenues:					
Oil & natural gas sales	$ 571,948	$ (18,148)	$ 186,421	$	$ 740,221
Other revenues	3,075	(807)			2,268
Total revenues	575,023	(18,955)	186,421		742,489
Costs and expenses:					
Lease operating	113,640	(1,652)	53,104		165,092
Pipeline operating	1,835				1,835
Exploration	2,356				2,356
Production and ad valorem taxes	27,146	(877)	26,810		53,079
Depreciation, depletion, and amortization	184,717	(10,519)		59,046 (a)	233,244
Impairment of proved oil and natural gas properties	6,600	(2,399)			4,201
General and administrative	125,358	(24,260)			101,098
Accretion of asset retirement obligations	5,581	(58)		280 (a)	5,803
(Gain) loss on commodity derivative instruments	(29,294)	(17)			(29,311)
(Gain) loss on sale of properties	(85,621)	89,548			3,927
Other, net	649				649
Total costs and expenses	352,967	49,766	79,914	59,326	541,973
Operating income	222,056	(68,721)	106,507	(59,326)	200,516
Other income (expense):					
Interest expense, net	(69,250)	53		(27,542)(b)	(117,843)
				(445)(c)	
				17,570 (d)	
				(18,009)(e)	
				1,411 (f)	
				20,814 (g)	
				29,868 (h)	
				(72,313)(i)	
Other, net	145	(2)			143
Total other income (expense)	(69,105)	51		(48,646)	(117,700)
Income (loss) before income taxes	152,951	(68,670)	106,507	(107,972)	82,816
Income tax benefit (expense)	(1,619)	1,147		(29,342)(j)	(29,814)
Net income (loss)	$ 151,332	$ (67,523)	$ 106,507	$ (137,314)	$ 53,002
Net income (loss) per common share(l)					
Basic					$ 0.28

Diluted	$	0.27
Weighted average common shares outstanding(1)		
Basic		192,500
Diluted		193,568

The accompanying notes are an integral part of this unaudited pro forma financial information.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENTS OF OPERATIONS

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2014

(in thousands, excepts per share amounts)	MRD Historical	Exclude BlueStone Holdings & Classic Pipeline	Wyoming Acquisition Historical	Other Pro Forma Adjustments	MRD Pro Forma Combined
Revenues:					
Oil & natural gas sales	$ 669,301	$ (1,689)	$ 91,199	$	$ 758,811
Other revenues	3,584	(550)			3,034
Total revenues	672,885	(2,239)	91,199		761,845
Costs and expenses:					
Lease operating	111,887	66	24,608		136,561
Pipeline operating	1,596				1,596
Exploration	1,465				1,465
Production and ad valorem taxes	33,623	(51)	11,943		45,515
Depreciation, depletion, and amortization	215,906	(743)		29,194 (a)	244,357
Impairment of proved oil and natural gas properties	67,181				67,181
Incentive unit compensation expense	969,390	(1,023)			968,367
General and administrative	61,061	(16)			61,045
Accretion of asset retirement obligations	4,601			140 (a)	4,741
(Gain) loss on commodity derivative instruments	11,580				11,580
(Gain) loss on sale of properties	3,057	110			3,167
Other	(12)				(12)
Total costs and expenses	1,481,335	(1,657)	36,551	29,334	1,545,563
Operating income (loss)	(808,450)	(582)	54,648	(29,334)	(783,718)
Other income (expense):					
Interest expense, net	(104,928)			(11,440)(b)	(108,998)
				(222)(c)	
				7,298 (d)	
				(8,874)(e)	
				18,402 (f)	
				15,090 (g)	
				14,164 (h)	
				(38,488)(i)	
Loss on extinguishment of debt	(37,248)				(37,248)
Other, net	102				102
Total other income (expense)	(142,074)			(4,070)	(146,144)
Income (loss) before income taxes	(950,524)	(582)	54,648	(33,404)	(929,862)
Income tax benefit (expense)	(14,398)			(7,438)(j)	(21,836)
Net income (loss)	$ (964,922)	$ (582)	$ 54,648	$ (40,842)	$ (951,698)
Net income (loss) per common share(l)					

Basic and diluted	$ (4.94)	$ (4.87)
Weighted average common shares outstanding(l)		
Basic	192,500	192,500
Diluted	192,500	192,500

The accompanying notes are an integral part of this unaudited pro forma financial information.

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UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

Note 1. Basis of Presentation

We are a Delaware corporation (MRD) formed by Memorial Resource Development LLC (MRD LLC) in January 2014 to own and acquire oil and natural gas properties in North America. MRD LLC was a Delaware limited liability company formed on April 27, 2011 by Natural Gas Partners VIII, L.P. (NGP VIII), Natural Gas Partners IX, L.P. (NGP IX) and NGP IX Offshore Holdings, L.P. (NGP IX Offshore) (collectively, the Funds) to own, acquire, exploit and develop oil and natural gas properties. The Funds are private equity funds managed by Natural Gas Partners (NGP).

On June 18, 2014, we completed our initial public offering (IPO). In connection with the closing of our IPO, the Funds contributed all of their interests in MRD LLC to MRD Holdco LLC (MRD Holdco). MRD LLC and its consolidated subsidiaries, which is our accounting predecessor, contributed the following to us in exchange for shares of our common stock (which MRD LLC immediately distributed to MRD Holdco): (1) 100% of its ownership interests in Classic Hydrocarbons Holdings, L.P. (Classic), Classic Hydrocarbons GP Co., L.L.C. (Classic GP), Black Diamond Minerals, LLC (Black Diamond), Beta Operating Company, LLC (Beta Operating), MRD Operating LLC (MRD Operating) and Memorial Production Partners GP LLC (MEMP GP), which owns a 0.1% general partner interest and 50% of the incentive distribution rights in Memorial Production Partners LP (MEMP), and (2) its 99.9% membership interest in WildHorse Resources, LLC (WildHorse Resources). In addition, certain former management members of WildHorse Resources contributed to us the remaining 0.1% membership interest in WildHorse Resources as well as exchanged their incentive units in exchange for shares of our common stock and cash consideration. MRD LLC merged into MRD Operating on June 27, 2014 upon the discharge of the indenture governing the $350.0 million 10.00% / 10.75% Senior PIK toggle notes due 2018 (PIK notes). Prior to this merger, MRD LLC distributed the following to MRD Holdco: (i) its interests in BlueStone Natural Resources Holdings, LLC (BlueStone Holdings), Golden Energy Partners LLC (Golden Energy) and Classic Pipeline & Gathering, LLC (Classic Pipeline) as well as two immaterial subsidiaries that were formed subsequent to December 31, 2013, (ii) the MEMP subordinated units, (iii) the right to the remaining cash to be released from the debt service reserve account in connection with the redemption or earlier discharge of the PIK notes plus the cash received from us in reimbursement of the interest paid on June 15, 2014 in respect of the PIK notes and (iv) approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy Partners LLC s assets in May 2014. Collectively, we refer to these transactions as the Restructuring.

We control MEMP through our ownership of MEMP GP. MEMP is a publicly traded limited partnership engaged in the acquisition, production and development of oil and natural gas properties in the United States. Due to our control of MEMP through the ownership of its general partner, we are required to consolidate MEMP for accounting and financial reporting purposes.

We have two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

- MRD reflects all of our consolidating subsidiaries except for MEMP and its subsidiaries.

- MEMP reflects the consolidated and combined operations of MEMP and its subsidiaries.

On July 1, 2014, MEMP acquired certain oil producing properties and related facilities located in the Lost Soldier and Wertz fields in Wyoming from Merit Energy Company, LLC and certain of its affiliates (Merit Energy) for an adjusted purchase price of approximately $911.7 million, including estimated customary post-closing adjustments, with an effective date of April 1, 2014 (the Wyoming Acquisition).

On July 15, 2014, MEMP issued 9,890,000 common units representing limited partner interests in MEMP (including 1,290,000 common units purchased pursuant to the full exercise of the underwriters option to

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

purchase additional common units) to the underwriters at an agreed offering price of $22.25 per unit generating total net proceeds of approximately $220.0 million after offering expenses. The net proceeds from the equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility. On September 9, 2014, MEMP issued 14,950,000 common units representing limited partner interests in MEMP (including 1,950,000 common units purchased pursuant to the full exercise of the underwriters option to purchase additional common units) to the public at an offering price of $22.29 per unit generating total net proceeds of approximately $321.6 million after deducting underwriting discounts of approximately $11.7 million and offering expenses. The net proceeds from the equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility. Collectively, we refer to these offerings as the MEMP Offerings.

On July 10, 2014, MRD completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes at par. On July 17, 2014, the MEMP completed a private placement of $500.0 million aggregate principal amount of 6.875% senior unsecured notes at 98.485% of par. Collectively, we refer to these offerings as the Debt Offerings.

The unaudited pro forma combined statements of operations of MRD is based on our audited and unaudited historical consolidated and combined statement of operations (including those of our predecessor) for the year ended December 31, 2013 and the nine months ended September 30, 2014, respectively, having been adjusted to give effect to the following transactions as if they had occurred on January 1, 2013 for pro forma statements of operations purposes:

- the exclusion of BlueStone Holdings and Classic Pipeline;
- the exclusion of the MEMP subordinated units;
- the Restructuring;
- the Wyoming Acquisition;
- the MEMP Offerings; and
- the Debt Offerings.

The unaudited pro forma combined financial statements should be read in conjunction with the notes thereto and with our historical financial statements (including those of our predecessor) and the historical financial statements of the Wyoming Acquisition, included elsewhere in this prospectus.

The actual effect of the transactions discussed in the accompanying notes ultimately may differ from the unaudited pro forma adjustments included herein. However, management believes that the assumptions utilized to prepare the pro forma adjustments provide a reasonable basis for presenting the significant effects of the transactions and that the unaudited pro forma adjustments are factually supportable, give appropriate effect to the impact of events that are directly attributable to the transactions, and reflect those items expected to have a continuing impact on MRD.

The unaudited pro forma combined financial statements of MRD are not necessarily indicative of financial results that would have been attained had the described transactions occurred on the dates indicated below or which could be achieved in the future because they necessarily exclude various operating expenses.

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Note 2. MRD Segment Stand-Alone Pro Forma Financial Statements

Unaudited Pro Forma Condensed Combined Statements of Operations For the Year Ended December 31, 2013

(in thousands)	MRD Segment Historical	Exclude BlueStone Holdings & Classic Pipeline	Other Pro Forma Adjustments	MRD Segment Pro Forma Combined
Revenues:				
Oil & natural gas sales	$ 230,751	$ (18,148)	$	$ 212,603
Other revenues	807	(807)		
Total revenues	231,558	(18,955)		212,603
Costs and expenses:				
Lease operating	25,006	(1,652)		23,354
Exploration	1,226			1,226
Production and ad valorem taxes	9,362	(877)		8,485
Depreciation, depletion, and amortization	87,043	(10,519)		76,524
Impairment of proved oil and natural gas properties	2,527	(2,399)		128
General and administrative	81,758	(24,260)		57,498
Accretion of asset retirement obligations	728	(58)		670
(Gain) loss on commodity derivative instruments	(3,013)	(17)		(3,030)
(Gain) loss on sale of properties	(82,773)	89,548		6,775
Other, net	2			2
Total costs and expenses	121,866	49,766		171,632
Operating income	109,692	(68,721)		40,971
Other income (expense):				
Interest expense, net	(27,349)	53	(18,009)(e)	(45,972)
			1,411 (f)	
			20,814 (g)	
			14,108 (h)	
			(37,000)(i)	
Earnings from equity investments	1,066		(797)(k)	269
Other, net	145	(2)		143
Total other income (expense)	(26,138)	51	(19,473)	(45,560)
Income (loss) before income taxes	83,554	(68,670)	(19,473)	(4,589)
Income tax benefit (expense)	(1,311)	1,147	1,816 (j)	1,652
Net income (loss)	$ 82,243	$ (67,523)	$ (17,657)	$ (2,937)

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

Unaudited Pro Forma Condensed Combined Statements of Operations Nine months ended September 30, 2014

(in thousands)	MRD Segment Historical	Exclude BlueStone Holdings & Classic Pipeline	Other Pro Forma Adjustments	MRD Segment Pro Forma Combined
Revenues:				
Oil & natural gas sales	$ 300,931	$ (1,689)	$	$ 299,242
Other revenues	561	(550)		11
Total revenues	301,492	(2,239)		299,253
Costs and expenses:				
Lease operating	18,657	66		18,723
Exploration	1,213			1,213
Production and ad valorem taxes	10,494	(51)		10,443
Depreciation, depletion, and amortization	107,496	(743)		106,753
Incentive unit compensation expense	969,390	(1,023)		968,367
General and administrative	29,301	(16)		29,285
Accretion of asset retirement obligations	495			495
(Gain) loss on commodity derivative instruments	(17,130)			(17,130)
(Gain) loss on sale of properties	3,057	110		3,167
Total costs and expenses	1,122,973	(1,657)		1,121,316
Operating income (loss)	(821,481)	(582)		(822,063)
Other income (expense):				
Interest expense, net	(44,355)		(8,874)(e)	(32,151)
			18,402 (f)	
			15,090 (g)	
			6,939 (h)	
			(19,353)(i)	
Loss on extinguishment of debt	(37,248)			(37,248)
Earnings from equity investments	(12,844)		12,862 (k)	18
Other, net	102			102
Total other income (expense)	(94,345)		25,066	(69,279)
Income (loss) before income taxes	(915,826)	(582)	25,066	(891,342)
Income tax benefit (expense)	(14,323)		(8,814)(j)	(23,137)
Net income (loss)	$ (930,149)	$ (582)	$ 16,252	$ (914,479)

Note 3. Pro Forma Adjustments and Assumptions

Unaudited Pro Forma Condensed Combined Statements of Operations

The following adjustments were made in the preparation of the unaudited pro forma condensed combined statements of operations for the year ended December 31, 2013 and the nine months ended September 30, 2014:

(a) Pro forma adjustment to reflect the depletion and depreciation on property and equipment and the accretion expense on asset retirement obligations associated with the Wyoming Acquisition.

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UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

(b) Pro forma adjustment to reflect the incurrence of interest expense on $847.4 million of additional borrowings under MEMP s revolving credit facility used to fund the Wyoming Acquisition. For the nine months ended September 30, 2014 and year ended December 31, 2013, pro forma interest expense was based on a rate of 2.70% and 3.25%, respectively. A one-eighth percentage point change in the interest rate would change pro forma interest associated with these additional borrowings by $0.5 million and $1.1 million for the nine months ended September 30, 2014 and year ended December 31, 2013, respectively.

(c) Pro forma adjustment to reflect the amortization of deferred financing costs as if the borrowing costs associated with the Wyoming Acquisition were incurred on January 1, 2013.

(d) Pro forma adjustment to reflect a reduction in interest expense on MEMP s revolving credit facility as a result of applying approximately $540.6 million of net proceeds from the MEMP Offerings.

(e) Pro forma adjustment to reflect the incurrence of interest expense on $620.4 million of borrowings by MRD under a new credit facility at LIBOR plus 2.50% and expenses on the unused borrowing base of 0.50%. Pro forma adjustment also reflects amortization of deferred financing costs of approximately $0.9 million and $0.4 million for the year ended December 31, 2013 and the nine months ended September 30, 2014, respectively. A one-eighth percentage point change in the interest rate would change pro forma interest by $0.8 million and $0.4 million for the year ended December 31, 2013 and the nine months ended September 30, 2014, respectively. The borrowings were primarily used to repay all amounts outstanding under WildHorse Resources credit agreements.

(f) Pro forma adjustment to reflect a reduction in interest expense on the PIK notes as a result of applying $357.0 million of net proceeds from the IPO to redeem the PIK notes in their entirety. The PIK notes were issued in December 2013.

(g) Pro forma adjustment to reflect a reduction in interest expense under WildHorse Resources revolving and second lien credit facilities associated with repayment of such debt with borrowings by MRD under a new credit facility. The second lien facility was entered into in June 2013.

(h) Pro forma adjustment to reflect reduction in interest expense under revolving credit facilities associated with repayment of such debt with net proceeds from the Debt Offerings.

(i) Pro forma adjustment to the incurrence of interest expense from the Debt Offerings. Pro forma adjustment also reflects amortization of deferred financing costs.

(j) Pro forma adjustment to reflect the estimated incremental income tax provision (benefit) associated with the historical results of operations and pro forma adjustments assuming the earnings had been subject to federal income tax as a subchapter C corporation using an effective tax rate of approximately 36.0%. This rate is inclusive of federal and state income taxes.

(k) Pro forma adjustment to reflect the exclusion of MEMP subordinated units.

(l) For the year ended December 31, 2013 basic earnings per share includes 192,500,000 shares of common stock outstanding at the completion of the IPO and diluted earnings per share also includes 1,068,422 restricted shares issued to our independent directors and certain employees in connection with the completion of the IPO. The restricted shares were antidilutive for the nine months ended September 30, 2014.

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UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

Note 4. Pro Forma Proved Reserves and Standardized Measure of Discounted Future Net Cash Flows

Users of this information should be aware that the process of estimating quantities of proved and proved developed oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will continue the project within a reasonable time.

Netherland, Sewell & Associates, Inc. (NSAI) was engaged to prepare all of our estimated proved reserves (by volume) at December 31, 2013. The proved reserves related to the Wyoming Acquisition Historical column were prepared for Merit Energy utilizing year-end estimates of reserve quantities provided by third-party independent petroleum engineering consultants. All proved reserves are located in the United States and all prices are held constant in accordance with SEC rules.

In accordance with SEC regulations, reserves at December 31, 2013 were estimated using the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period.

The following table sets forth estimates of the net reserves as of December 31, 2013:

	MRD LLC Historical Equivalent (MMcfe)	Exclude BlueStone Holdings Equivalent (MMcfe)	Wyoming Acquisition Historical Equivalent (MMcfe)	MRD Pro Forma Combined Equivalent (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of year	2,074,990	(8,057)	208,884	2,275,817
Extensions and discoveries	295,832			295,832
Purchase of minerals in place	57,737			57,737
Production	(103,122)	1,690	(12,492)	(113,924)
Sales of minerals in place	(27,169)	4,178		(22,991)
Revision of previous estimates	(157,586)	2,189	2,532	(152,865)

End of year(1)	2,140,682		198,924	2,339,606
Proved developed reserves:				
Beginning of year	957,573	(4,901)	195,492	1,148,164
End of year	984,534		188,508	1,173,042
Proved undeveloped reserves:				
Beginning of year	1,117,417	(3,156)	13,392	1,127,563
End of year	1,156,148		10,416	1,166,564

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(1) The MRD pro forma combined reserves include 1,212,815 MMcfe related to the MEMP Segment and Wyoming Acquisition that would be attributable to noncontrolling interests based on a 0.1% ownership by MRD.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

The standardized measure of discounted future net cash flows presented below is computed by applying first of month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to proved reserves. We do not believe the standardized measure provides a reliable estimate of the expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first of month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year as prices change.

The standardized measure of discounted future net cash flows is as follows for the year ended December 31, 2013 (in thousands):

	MRD LLC Historical	Restructuring Related Adjustments	Wyoming Acquisition Historical	MRD Pro Forma Combined
Future cash inflows	$ 12,614,998	$	$ 2,977,811	$ 15,592,809
Future production costs	(4,306,398)		(1,266,229)	(5,572,627)
Future development costs	(2,038,803)		(76,400)	(2,115,203)
Future income tax expense(1)		(821,733)		(821,733)
Future net cash flows for estimated timing of cash flows	6,269,797	(821,733)	1,635,182	7,083,246
10% annual discount for estimated timing of cash flows	(3,192,733)	392,018	(741,493)	(3,542,208)
Standardized measure of discounted future net cash flows(2)	$ 3,077,064	$ (429,715)	$ 893,689	$ 3,541,038

(1) Pro forma adjustment to reflect the estimated incremental income tax provision associated with the historical results of operations and pro forma adjustments for the MRD Segment assuming the earnings had been subject to federal income tax as a subchapter C corporation using an effective tax rate of approximately 36%. This rate is inclusive of federal and state income taxes.

(2) The MRD pro forma combined standardized measure of discounted future net cash flows include $2,499,299 related to the MEMP Segment and Wyoming Acquisition that would be attributable to noncontrolling interests based on a 0.1% ownership by MRD.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during the year ended December 31, 2013 (in thousands):

	MRD LLC Historical	Exclude BlueStone Holdings	Restructuring Related Adjustments	Wyoming Acquisition Historical	MRD Pro Forma Combined
Beginning of year	$ 2,910,511	$ (35,469)	$	$ 823,299	$ 3,698,341
Sale of oil and natural gas produced, net of production costs	(430,964)	13,694		(106,519)	(523,789)
Purchase of minerals in place	74,337				74,337
Sale of minerals in place	(54,091)	24,718			(29,373)
Extensions and discoveries	437,427				437,427
Changes in income taxes			(429,715)		(429,715)
Changes in prices and costs	(85,731)			63,290	(22,441)
Previously estimated development costs incurred	261,787	(4,048)		30,858	288,597
Net changes in future development costs	(17,514)			(7,957)	(25,471)
Revisions of previous quantities	(327,926)			11,919	(316,007)
Accretion of discount	287,535			78,857	366,392
Change in production rates and other	21,693	1,105		(58)	22,740
End of year	$ 3,077,064	$	$ (429,715)	$ 893,689	$ 3,541,038

MRD Segment

The following table sets forth estimates of the net reserves as of December 31, 2013:

	MRD Segment Historical Equivalent (MMcfe)	Exclude BlueStone Holdings Equivalent (MMcfe)	MRD Segment Pro Forma Combined Equivalent (MMcfe)
Proved developed and undeveloped reserves:			
Beginning of year	1,059,895	(8,057)	1,051,838
Extensions and discoveries	210,652		210,652
Purchase of minerals in place	39,183		39,183
Production	(46,819)	1,690	(45,129)
Sales of minerals in place	(27,169)	4,178	(22,991)
Revision of previous estimates	(110,165)	2,189	(107,976)
End of year(1)	1,125,577		1,125,577
Proved developed reserves:			

Beginning of year	337,869	(4,901)	332,968
End of year	367,641		367,641
Proved undeveloped reserves:			
Beginning of year	722,026	(3,156)	718,870
End of year	757,936		757,936

(1) MRD segment historical column includes reserves of 41,077 MMcfe attributable to noncontrolling interests and the previous owners.

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UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

The standardized measure of discounted future net cash flows is as follows for the year ended December 31, 2013 (in thousands):

	MRD Segment Historical	Exclude BlueStone Holdings	Restructuring Related Adjustments	MRD Segment Pro Forma Combined
Future cash inflows	$ 5,722,848	$	$	$ 5,722,848
Future production costs	(1,587,374)			(1,587,374)
Future development costs	(1,352,945)			(1,352,945)
Future income tax expense(1)			(760,433)	(760,433)
Future net cash flows for estimated timing of cash flows	2,782,529		(760,433)	2,022,096
10% annual discount for estimated timing of cash flows	(1,313,577)		358,986	(954,591)
Standardized measure of discounted future net cash flows(2)	$ 1,468,952	$	$ (401,447)	$ 1,067,505

(1) Pro forma adjustment to reflect the estimated incremental income tax provision associated with the historical results of operations and pro forma adjustments for the MRD Segment assuming the earnings had been subject to federal income tax as a subchapter C corporation using an effective tax rate of approximately 36%. This rate is inclusive of federal and state income taxes.

(2) The MRD Segment Historical column includes $63,422 attributable to noncontrolling interests and the previous owners and on a pro forma basis includes $40,704 attributable to noncontrolling interests and the previous owners.

The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during the year ended December 31, 2013 (in thousands):

	MRD Segment Historical	Exclude BlueStone Holdings	Restructuring Related Adjustments	MRD Segment Pro Forma Combined
Beginning of year	$ 1,320,595	$ (35,469)	$	$ 1,285,126
Sale of oil and natural gas produced, net of production costs	(196,444)	13,694		(182,750)
Purchase of minerals in place	51,177			51,177
Sale of minerals in place	(54,091)	24,718		(29,373)
Extensions and discoveries	301,004			301,004
Changes in income taxes			(401,447)	(401,447)
Changes in prices and costs	(11,336)			(11,336)
Previously estimated development costs incurred	87,297	(4,048)		83,249
Net changes in future development costs	57,353			57,353
Revisions of previous quantities	(186,804)			(186,804)
Accretion of discount	128,544			128,544
Change in production rates and other	(28,343)	1,105		(27,238)
End of year	$ 1,468,952	$	$ (401,447)	$ 1,067,505

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED CONDENSED CONSOLIDATED AND COMBINED BALANCE SHEETS

(In thousands, except outstanding shares)

	September 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,316	$ 77,721
Restricted cash		35,000
Accounts receivable:		
Oil and natural gas sales	102,578	68,764
Joint interest owners and other	19,116	19,958
Affiliates		4,652
Short-term derivative instruments	37,421	9,289
Prepaid expenses and other current assets	20,696	19,513
Total current assets	190,127	234,897
Property and equipment, at cost:		
Oil and natural gas properties, successful efforts method	4,544,176	3,037,298
Other	15,477	10,331
Accumulated depreciation, depletion and impairment	(877,843)	(627,925)
Oil and natural gas properties, net	3,681,810	2,419,704
Long-term derivative instruments	34,515	48,616
Restricted investments	76,268	73,385
Restricted cash	260	15,506
Other long-term assets	38,687	37,053
Total assets	$ 4,021,667	$ 2,829,161
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 16,846	$ 20,734
Accounts payable affiliates	810	1,975
Revenues payable	59,512	56,091
Accrued liabilities	179,381	98,130
Short-term derivative instruments	5,109	9,711
Total current liabilities	261,658	186,641
Long-term debt MRD Segment	628,000	871,150
Long-term debt MEMP Segment	1,483,800	792,067
Asset retirement obligations	119,510	111,679
Long-term derivative instruments	15,275	6,080
Deferred tax liabilities	50,643	3,106
Other long-term liabilities	3,782	306
Total liabilities	2,562,668	1,971,029
Commitments and contingencies (Note 15)		
Equity:		
Stockholders equity (deficit):		
Preferred stock, $.01 par value: 50,000,000 shares authorized; no shares issued and outstanding		
Common stock, $.01 par value: 600,000,000 shares authorized; 193,559,211 shares issued and outstanding at September 30, 2014; no shares authorized, issued or outstanding at December 31, 2013	1,936	
Additional paid-in capital	1,386,143	
Accumulated earnings (deficit)	(951,801)	

Total stockholders equity	436,278	
Members equity:		
Members		237,186
Previous owners (Note 1)		40,331
Total members equity		277,517
Noncontrolling interests	1,022,721	580,615
Total equity	1,458,999	858,132
Total liabilities and equity	$ 4,021,667	$ 2,829,161

See Accompanying Notes to Unaudited Condensed Consolidated and Combined Financial Statements.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED CONDENSED STATEMENTS OF

CONSOLIDATED AND COMBINED OPERATIONS

(In thousands, except per share amounts)

	For the Nine Months Ended September 30, 2014	2013
Revenues:		
Oil & natural gas sales	$ 669,301	$ 420,857
Pipeline tariff income and other	3,584	1,884
Total revenues	672,885	422,741
Costs and expenses:		
Lease operating	111,887	81,746
Pipeline operating	1,596	1,343
Exploration	1,465	2,265
Production and ad valorem taxes	33,623	23,478
Depreciation, depletion, and amortization	215,906	132,328
Impairment of proved oil and natural gas properties	67,181	21
Incentive unit compensation expense (Note 12)	969,390	19,069
General and administrative	61,061	55,982
Accretion of asset retirement obligations	4,601	4,016
(Gain) loss on commodity derivative instruments	11,580	(29,556)
(Gain) loss on sale of properties	3,057	(86,218)
Other, net	(12)	622
Total costs and expenses	1,481,335	205,096
Operating income (loss)	(808,450)	217,645
Other income (expense):		
Interest expense, net	(104,928)	(41,994)
Loss on extinguishment of debt	(37,248)	
Other, net	102	81
Total other income (expense)	(142,074)	(41,913)
Income (loss) before income taxes	(950,524)	175,732
Income tax benefit (expense)	(14,398)	(1,432)
Net income (loss)	(964,922)	174,300
Net income (loss) attributable to noncontrolling interest	(34,851)	42,134
Net income (loss) attributable to Memorial Resource Development Corp.	(930,071)	132,166
Net (income) loss allocated to members	(20,305)	(122,639)
Net (income) loss allocated to previous owners	(1,425)	(9,527)
Net income (loss) available to common stockholders	$ (951,801)	$

Earnings per common share: (Note 10)			
Basic	$	(4.94)	$
Diluted	$	(4.94)	$
Weighted average common and common equivalent shares outstanding:			
Basic		192,500	
Diluted		192,500	

See Accompanying Notes to Unaudited Condensed Consolidated and Combined Financial Statements.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED CONDENSED STATEMENTS OF

CONSOLIDATED AND COMBINED CASH FLOWS

(In thousands)

	For the Nine Months Ended September 30, 2014	2013
Cash flows from operating activities:		
Net income (loss)	$ (964,922)	$ 174,300
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	215,906	132,328
Impairment of proved oil and natural gas properties	67,181	21
(Gain) loss on derivatives	12,737	(29,487)
Cash settlements (paid) received on derivative instruments	22,174	21,356
Loss on extinguishment of debt	30,248	
Amortization of deferred financing costs	5,492	6,193
Accretion of senior notes net discount	1,888	161
Accretion of asset retirement obligations	4,601	4,016
Amortization of equity awards	6,874	2,322
(Gain) loss on sale of properties	3,057	(86,218)
Non-cash compensation expense	941,659	1,057
Exploration costs	868	
Deferred income tax expense (benefit)	13,916	
Changes in operating assets and liabilities:		
Accounts receivable	(22,117)	560
Prepaid expenses and other assets	297	(2,562)
Payables and accrued liabilities	67,324	13,034
Other	2,625	95
Net cash provided by operating activities	365,460	237,176
Cash flows from investing activities:		
Acquisitions of oil and natural gas properties	(1,083,167)	(104,926)
Additions to oil and gas properties	(457,838)	(257,513)
Additions to other property and equipment	(9,134)	(1,184)
Additions to restricted investments	(2,883)	(4,263)
Deposits for property acquisitions		(25,310)
Decrease (increase) in restricted cash	49,946	653
Proceeds from the sale of oil and natural gas properties	6,700	156,799
Other	(301)	(139)
Net cash used in investing activities	(1,496,677)	(235,883)
Cash flows from financing activities:		
Advances on revolving credit facilities	2,464,800	478,055
Payments on revolving credit facilities	(2,441,900)	(900,368)
Borrowings under second lien credit facility		325,000
Redemption of second lien credit facility	(328,282)	
Proceeds from the issuances of senior notes	1,092,425	397,563
Redemption of senior notes	(351,808)	
Deferred financing costs	(30,284)	(23,839)
Purchase of additional interests in consolidated subsidiaries	(3,292)	(1,270)
Contributions from previous owners		1,214
Proceeds from initial public offering	408,500	
Costs incurred in conjunction with initial public offering	(28,198)	
Proceeds from MEMP public offering	553,288	179,371
Costs incurred in conjunction with MEMP public offering	(12,222)	(7,592)
Contributions from NGP affiliates related to sale of properties	1,165	2,013

Distributions to the Funds		(363,437)
Distributions to MRD Holdco	(59,803)	
Distributions to noncontrolling interests	(101,327)	(51,319)
Distribution to NGP affiliates related to purchase of assets	(66,693)	
Distribution to NGP affiliates related to sale of assets, net of cash received	(32,770)	
Distributions made by previous owners		(3,130)
Other	213	
Net cash provided by financing activities	1,063,812	32,261
Net change in cash and cash equivalents	(67,405)	33,554
Cash and cash equivalents, beginning of period	77,721	49,391
Cash and cash equivalents, end of period	$ 10,316	$ 82,945
Supplemental cash flows:		
Cash paid for interest	$ 67,449	$ 22,959
Noncash investing and financing activities:		
Change in capital expenditures in payables and accrued liabilities	29,137	25,017
Assumptions of asset retirement obligations related to properties acquired or drilled	5,053	3,478
Accounts receivable related to acquisitions and divestitures	4,271	

See Accompanying Notes to Unaudited Condensed Consolidated and Combined Financial Statements.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED AND COMBINED EQUITY

(In thousands)

	For the Nine Months Ended September 30, 2014	2013
STOCKHOLDERS EQUITY		
Preferred stock		
Balance, beginning and end of period	$	$
Common stock		
Balance, beginning of period		
Issuance of shares in connection with restructuring transactions (see Note 1)	1,710	
Issuance of shares in connection with initial public offering (see Note 1)	215	
Restricted stock awards	11	
Balance, end of period	1,936	
Additional paid-in capital		
Balance, beginning of period		
Issuance of shares in connection with restructuring transactions (see Note 1)	913,152	
Issuance of shares in connection with initial public offering (see Note 1)	379,962	
Tax related effects in connection with restructuring transactions and initial public offering	(43,251)	
Restricted stock awards	(11)	
Amortization of restricted stock awards	1,487	
Contribution related to MRD Holdco incentive unit compensation expense (see Note 12)	137,307	
Purchase of noncontrolling interests	(2,881)	
Other	378	
Balance, end of period	1,386,143	
Accumulated earnings (deficit)		
Balance, beginning of period		
Net income (loss) allocation	(951,801)	
Balance, end of period	(951,801)	
Total stockholders equity	436,278	
MEMBERS EQUITY		
Members		
Balance, beginning of period	237,186	811,614
Net income (loss) allocation	20,305	122,639
Contribution related to sale of assets to NGP affiliate	1,165	
Net book value of assets sold to NGP affiliate	(621)	
Net book value of assets acquired from NGP affiliates	45,059	
Distribution to NGP affiliates in connection with acquisition of assets	(66,693)	
Distribution of net assets to MRD Holdco	(123,078)	
Distribution of shares received in connection with restructuring transactions to MRD Holdco	(110,510)	
Distributions		(363,437)
Net equity deemed contribution (distribution) related to net assets transferred to MEMP	(2,659)	2,560
Impact of equity transactions of MEMP		24,024
Other	(154)	(47)

Balance, end of period		597,353
Previous Owners		
Balance, beginning of period	40,331	233,433
Net income (loss) allocation	1,425	9,527
Contributions		1,214
Distributions		(3,130)
Net book value of assets acquired from NGP affiliates	(41,756)	
Other		(2,299)
Balance, end of period		238,745
Total members equity		836,098
NONCONTROLLING INTERESTS		
Noncontrolling interests		
Balance, beginning of period	580,615	231,662
Net income (loss) allocation	(34,851)	42,134
Net proceeds from MEMP public equity offering	540,987	171,779
Distributions	(101,327)	(51,319)
Net equity deemed contribution (distribution) related to net assets transferred to MEMP	2,659	(2,560)
Purchase of noncontrolling interests	(411)	(1,270)
Impact of equity transactions of MEMP		(24,024)
Amortization of MEMP equity awards	5,387	2,321
Distribution of net assets to MRD Holdco	29,994	
Other	(332)	
Balance, end of period	1,022,721	368,723
TOTAL EQUITY		
Total equity	1,458,999	1,204,821

See Accompanying Notes to Unaudited Condensed Consolidated and Combined Financial Statements.

MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Note 1. Background, Organization and Basis of Presentation

Overview

Memorial Resource Development Corp. (the Company) is a publicly traded Delaware corporation, the common shares of which are listed on the NASDAQ Global Market (NASDAQ) under the symbol MRD. Unless the context requires otherwise, references to we, us, our, MRD, or Company are intended to mean the business and operations of Memorial Resource Development Corp. and its consolidated subsidiaries.

The Company was formed by Memorial Resource Development LLC (MRD LLC) in January 2014 to exploit, develop and acquire natural gas, NGL and oil properties in North America. MRD LLC was a Delaware limited liability company formed on April 27, 2011 by Natural Gas Partners VIII, L.P. (NGP VIII), Natural Gas Partners IX, L.P. (NGP IX) and NGP IX Offshore Holdings, L.P. (NGP IX Offshore) (collectively, the Funds) to exploit, develop and acquire natural gas, NGL and oil properties. The Funds are private equity funds managed by Natural Gas Partners (NGP). MRD LLC s consolidated and combined financial statements represent our predecessor for accounting and financial reporting purposes prior to our initial public offering.

Initial Public Offering and Restructuring Transactions

On June 18, 2014, the Company completed its initial public offering of 21,500,000 common units at a price of $19.00 per share, which generated net proceeds to the Company of approximately $380.2 million after deducting underwriting discounts and commissions and other offering related fees and expenses. The following restructuring events and transactions occurred in connection with our initial public offering:

- The Funds contributed all of their interests in MRD LLC to MRD Holdco LLC (MRD Holdco) and the members of our management who owned incentive units in MRD LLC exchanged those incentive units for substantially identical incentive units in MRD Holdco, after which MRD Holdco owned 100% of MRD LLC;

- WildHorse Resources, LLC (WildHorse Resources) sold its subsidiary, WildHorse Resources Management Company, LLC (WHR Management Company), to an affiliate of the Funds for approximately $0.2 million in cash, and WHR Management Company entered into a services agreement with the Company and WildHorse Resources pursuant to which WHR Management Company will provide transition services to WildHorse Resources;

- Classic Hydrocarbons Holdings, L.P. (Classic) and Classic Hydrocarbons GP Co., L.L.C. (Classic GP) distributed to MRD LLC the ownership interests in Classic Pipeline & Gathering, LLC (Classic Pipeline), which owns certain midstream assets in Texas, and Black Diamond Minerals, LLC (Black Diamond) distributed to MRD LLC its ownership interests in Golden Energy Partners LLC (Golden Energy), which sold all of its assets in May 2014;

MRD LLC contributed to us substantially all of its assets, comprised of: (i) 100% of the ownership interests in Classic, Classic GP, Black Diamond, Beta Operating Company, LLC (Beta Operating), Memorial Resource Finance Corp., MRD Operating LLC (MRD Operating), Memorial Production Partners GP LLC (MEMP GP) (including MEMP GP s ownership of 50% of Memorial Production Partners LP s (MEMP) incentive distribution rights) and (ii) 99.9% of the membership interests in WildHorse Resources;

We issued 128,665,677 shares of our common stock to MRD LLC, which MRD LLC immediately distributed to MRD Holdco;

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

We assumed the obligations of MRD LLC under the indenture governing the $350 million in aggregate principal amount of 10.00% / 10.75% Senior PIK Toggle Notes due 2018 (the PIK notes) and reimbursed MRD LLC for the June 15, 2014 interest payment made on the PIK notes;

Certain former management members of WildHorse Resources contributed to us their outstanding incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources, and we issued 42,334,323 shares of our common stock and paid cash consideration of $30.0 million to such former management members of WildHorse Resources;

We entered into a registration rights agreement and a voting agreement with MRD Holdco and certain former management members of WildHorse Resources;

We entered into a new $2.0 billion revolving credit facility (see Note 8) and used approximately $614.5 million in borrowings under that facility to repay all amounts outstanding under WildHorse Resources credit agreements, to partially fund the cash consideration payable to the former management members of WildHorse Resources and to reimburse MRD LLC for the June 15, 2014 interest payment made on the PIK notes;

Notice of redemption was given to the PIK notes trustee (see Note 8) specifying a redemption date of July 16, 2014 and indicating that a portion of the net proceeds from our initial public offering, which temporarily reduced amounts outstanding under our new revolving credit facility, would be used to redeem the PIK notes at a redemption price of 102% of the principal amount of the PIK notes plus accrued and unpaid interest thereon to the date of redemption;

MRD Operating entered into a merger agreement with MRD LLC pursuant to which after the termination or earlier discharge of the PIK notes MRD LLC would merge into MRD Operating;

MRD LLC distributed to MRD Holdco the following: (i) BlueStone Natural Resources Holdings, LLC (BlueStone), which sold substantially all of its assets in July 2013 for $117.9 million, MRD Royalty LLC, which owns certain leasehold interests and overriding royalty interests in Texas and Montana, MRD Midstream LLC, which owns an indirect interest in certain midstream assets in North Louisiana, Golden Energy and Classic Pipeline; (ii) 5,360,912 subordinated units of MEMP; (iii) the right to the remaining cash to be released from the debt service reserve account in connection with the redemption or earlier discharge of the PIK notes plus the cash received from us in reimbursement of the interest paid on June 15, 2014 in respect of the PIK notes; and (iv) approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy s assets in May 2014;

We irrevocably deposited with the PIK notes trustee approximately $360.0 million on June 27, 2014, which was an amount sufficient to fund the redemption of the PIK notes on the redemption date and to satisfy and discharge our obligations under the PIK notes and the related indenture. The discharge became effective upon the irrevocable deposit of the funds with the PIK notes trustee; and

MRD LLC merged into MRD Operating.

Previous Owners

References to the previous owners for accounting and financial reporting purposes refer collectively to:

Certain oil and natural gas properties and related assets primarily in the Permian Basin, East Texas and the Rockies that MEMP acquired through equity transactions on October 1, 2013 from certain affiliates of NGP. On October 1, 2013, MEMP acquired Boaz Energy, LLC (Boaz), Crown Energy Partners, LLC (Crown), the Crown net profits interest and overriding royalty interest (Crown NPI/ORRI), Propel Energy SPV LLC (Propel SPV), together with its wholly-owned subsidiary Propel Energy Services,

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

LLC (Propel Energy Services), and Stanolind Oil and Gas SPV LLC (Stanolind SPV) from Boaz Energy Partners, LLC (Boaz Energy Partners), Crown Energy Partners Holdings, LLC (Crown Holdings), Propel Energy, LLC (Propel Energy) and Stanolind Oil and Gas LP (Stanolind), all of which are primarily owned by two of the Funds.

A net profits interest that WildHorse Resources purchased from NGP Income Co-Investment Fund II, L.P. (NGPCIF) on February 28, 2014 (NGPCIF NPI). NGPCIF is controlled by NGP. Upon the completion of the 2010 Petrohawk and Clayton Williams acquisitions, WildHorse Resources sold a net profits interest in these properties to NGPCIF. Since WildHorse Resources sold the net profits interest, the historical results are accounted for as a working interest for all periods.

Our unaudited financial statements reported herein include the financial position and results attributable to: (i) those certain oil and natural gas properties and related assets that MEMP acquired through equity transactions on October 1, 2013 from Boaz Energy Partners, Crown Holdings, Propel Energy and Stanolind and (ii) NGPCIF NPI.

Basis of Presentation

The financial statements reported herein include the financial position and results attributable to both our predecessor and the previous owners on a combined basis for periods prior to our initial public offering. For periods after the completion of our public offering, our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest. Due to our control of MEMP through our ownership of MEMP GP, we are required to consolidate MEMP for accounting and financial reporting purposes. MEMP is owned 99.9% by its limited partners and 0.1% by MEMP GP.

All material intercompany transactions and balances have been eliminated in preparation of our consolidated and combined financial statements. Our results of operations for the nine months ended September 30, 2014 are not necessarily indicative of results expected for the full year. In our opinion, the accompanying unaudited condensed consolidated and combined financial statements include all adjustments of a normal recurring nature necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate and make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) have been condensed or omitted pursuant to the rules and regulations of the United States Securities and Exchange Commission (SEC).

We have two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties (See Note 14). Our reportable business segments are as follows:

MRD reflects the combined operations of the Company, MRD LLC, WildHorse Resources and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.

MEMP reflects the combined operations of MEMP, its previous owners, and historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

Segment financial information has been retrospectively revised for the following common control transactions for comparability purposes:

acquisition by MEMP of all the outstanding membership interests in Tanos Energy, LLC (Tanos) from MRD LLC for a purchase price of approximately $77.4 million on October 1, 2013;

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

acquisition by MEMP of all the outstanding membership interests in Prospect Energy, LLC (Prospect Energy) from Black Diamond for a purchase price of approximately $16.3 million on October 1, 2013;

acquisition by MEMP of certain of the oil and natural gas properties in Jackson County, Texas from MRD LLC for a purchase price of approximately $2.6 million on October 1, 2013; and

acquisition by MEMP of all the outstanding membership interests in WHT Energy Partners LLC (WHT) from WildHorse Resources and Tanos for a purchase price of approximately $200.0 million on March 28, 2013.

Note 2. Summary of Significant Accounting Policies

Use of Estimates

The preparation of the accompanying unaudited condensed consolidated and combined financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated and combined financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Significant estimates include, but are not limited to, oil and natural gas reserves; depreciation, depletion, and amortization of proved oil and natural gas properties; future cash flows from oil and natural gas properties; impairment of long-lived assets; fair value of derivatives; fair value of equity compensation; fair values of assets acquired and liabilities assumed in business combinations; and asset retirement obligations.

Principles of Consolidation and Combination

Our consolidated financial statements include our accounts and those of our subsidiaries in which we have a controlling interest. Likewise, the combined financial statements include those of our predecessor and the previous owners.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and all highly liquid investments with original contractual maturities of three months or less.

Concentrations of Credit Risk

Cash balances, accounts receivable, restricted investments and derivative financial instruments are financial instruments potentially subject to credit risk. Cash and cash equivalents are maintained in bank deposit accounts which, at times, may exceed the federally insured limits. Management periodically reviews and assesses the financial condition of the banks to mitigate the risk of loss. Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with MEMP s offshore Southern California oil and gas properties. These restricted investments may consist of money market deposit accounts, money market mutual funds, commercial paper, and U.S. Government securities, all held with credit-worthy financial institutions. Derivative financial instruments are generally executed with major financial institutions that expose us to market and credit risks and which may, at times, be concentrated with certain counterparties. The creditworthiness of the counterparties is subject to continual review. We rely upon netting arrangements with counterparties to reduce credit exposure. We have not experienced any losses from such instruments.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Oil and natural gas are sold to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. Accounts receivable from joint operations are from a number of oil and natural gas companies, partnerships, individuals, and others who own interests in the properties operated by us and our predecessor. Generally, operators of crude oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells, minimizing the credit risk associated with these receivables. Additionally, management believes that any credit risk imposed by a concentration in the oil and natural gas industry is mitigated by the creditworthiness of its customer base. An allowance for doubtful accounts is recorded after all reasonable efforts have been exhausted to collect or settle the amount owed. Any amounts outstanding longer than the contractual terms are considered past due. Management determined that an allowance for uncollectible accounts was unnecessary at both September 30, 2014 and December 31, 2013, respectively.

If we were to lose any one of our customers, the loss could temporarily delay production and the sale of oil and natural gas in the related producing region. If we were to lose any single customer, we believe that a substitute customer to purchase the impacted production volumes could be identified.

Oil and Natural Gas Properties

Oil and natural gas exploration, development and production activities are accounted for in accordance with the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells, and development costs are capitalized. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete. Exploration costs such as geological, geophysical, and seismic costs are expensed as incurred.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties are subject to depreciation and depletion. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated field. Capitalized drilling and development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves.

On the sale or retirement of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated depreciation, depletion, and amortization are removed from the property accounts, and any gain or loss is recognized.

Impairments

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates, less than expected production, drilling results, higher operating and development costs, or lower commodity prices. The estimated undiscounted future cash flows expected in connection with the property are compared to the carrying value of the property to determine if the carrying amount is recoverable. If the carrying value of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

Unproved oil and natural gas properties are assessed for impairment on a property-by-property basis. A loss is recognized by providing a valuation allowance if the assessment indicates an impairment. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management.

Asset Retirement Obligations

An asset retirement obligation associated with retiring long-lived assets is recognized as a liability on a discounted basis in the period in which the legal obligation is incurred and becomes determinable, with an equal amount capitalized as an addition to oil and natural gas properties, which is allocated to expense over the useful life of the asset. Generally, oil and gas producing companies incur such a liability upon acquiring or drilling a well. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. Upon settlement of the liability, a gain or loss is recognized as a component of exploration costs to the extent the actual costs differ from the recorded liability. See Note 6 for further discussion of asset retirement obligations.

Oil and Gas Reserves

The estimates of proved oil and natural gas reserves utilized in the preparation of the consolidated and combined financial statements are estimated in accordance with the rules established by the SEC and the Financial Accounting Standards Board (FASB). These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

Other Property & Equipment

Other property and equipment is stated at historical costs and is comprised primarily of vehicles, furniture, fixtures, and computer hardware and software. Depreciation of other property and equipment is calculated using the straight-line method generally based on estimated useful lives of three to five years.

Restricted Investments

Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with MEMP s offshore Southern California oil and gas properties. These investments are classified as held-to-maturity, and such investments are stated at amortized cost. Interest earned on these investments is included in interest expense net in the statement of operations. The amortized cost of such investments is adjusted for amortization of premiums and accretion of

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discounts to maturity. At September 30, 2014, these restricted investments consisted of money market deposit accounts, money market mutual funds, commercial paper, and U.S. Government securities. See Note 7 for additional information.

Debt Issuance Costs

These costs are recorded on the balance sheet and amortized over the term of the associated debt using the straight-line method which approximates the effective yield method.

Revenue Recognition

Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties due to third parties. Oil and natural gas revenues are recorded using the sales method. Under this method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of our proportionate share of the remaining recoverable reserves on the underlying properties.

Derivative Instruments

Commodity derivative financial instruments (e.g., swaps, collars, and put options) are used to reduce the impact of natural gas and oil price fluctuations. Interest rate swaps are used to manage exposure to interest rate volatility, primarily as a result of variable rate borrowings under the credit facilities. Every derivative instrument is recorded on the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative s fair value are recognized in earnings as we have not elected hedge accounting for any of our derivative positions.

Income Tax

Prior to our initial public offering, MRD LLC was organized as a pass-through entity for federal income tax purposes and was not subject to federal income taxes; however, certain of its consolidating subsidiaries were taxed as corporations and subject to federal income taxes. We are organized as a taxable C corporation and subject to federal and certain state income taxes. We are also subject to the Texas margin tax and certain aspects of the tax make it similar to an income tax as the tax is assessed on 1% of taxable margin apportioned to operations in Texas.

Deferred federal and state income taxes are provided on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis. If it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. A tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through final settlement with a taxing authority. There were no uncertain tax positions that required recognition in the financial statements at both September 30, 2014 and December 31, 2013, respectively.

In June 2014, we recorded a deferred tax liability of approximately $43.3 million in stockholders equity in connection with our initial public offering and the related restructuring transactions. The tax bases of our assets and liabilities changed as a result our initial public offering and the related restructuring transactions, which represented a transaction among stockholders.

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Earnings Per Share

Basic earnings per share (EPS) is computed based on the average number of shares of common stock outstanding for the period. Diluted EPS includes the effect of the Company s outstanding restricted stock awards if the inclusion of these awards is dilutive. See Note 10 for additional information.

Incentive-Based Compensation Arrangements

The fair value of equity-classified awards (e.g., restricted stock awards) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards are recognized over the requisite service or vesting period of an award based on the fair value of the award re-measured at each reporting period. Generally, no compensation expense is recognized for equity instruments that do not vest.

Prior to the restructuring transactions, the governing documents of MRD LLC and certain of its subsidiaries, including WildHorse Resources and BlueStone, provided for the issuance of incentive units. The incentive units were subject to performance conditions that affected their vesting. Compensation cost was recognized only if the performance condition was probable of being satisfied at each reporting date.

In connection with the restructuring transactions, the MRD LLC incentive units were exchanged for substantially identical units in MRD Holdco, and such incentive units entitle holders thereof to portions of future distributions by MRD Holdco. While any such distributions made by MRD Holdco will not involve any cash payment by us, we will be required to recognize non-cash compensation expense, which may be material, in future periods. The compensation expense recognized by us related to the incentive units will be offset by a deemed capital contribution from MRD Holdco.

See Notes 11 and 12 for further information.

Current Liabilities Accrued liabilities

Current accrued liabilities consisted of the following at the dates indicated (in thousands):

	September 30,	December 31,

	2014	2013
Accrued capital expenditures	$ 77,716	$ 48,579
Accrued lease operating expense	18,142	13,240
Accrued general and administrative expenses	11,986	14,485
Accrued ad valorem and production taxes	26,466	3,541
Accrued interest payable	41,857	11,934
Accrued environmental	571	577
Other miscellaneous, including operator advances	2,643	5,774
	$ 179,381	$ 98,130

New Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the FASB issued a comprehensive new revenue recognition standard for contracts with customers that will supersede most current revenue recognition guidance, including industry-specific guidance. The core principle of this standard is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the

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consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this core principle, the standard provides a five-step analysis of transactions to determine when and how revenue is recognized. Other major provisions include the capitalization and amortization of certain contract costs, ensuring the time value of money is considered in the transaction price, and allowing estimates of variable consideration to be recognized before contingencies are resolved in certain circumstances. This guidance also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity s contracts with customers. The new standard is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Early application is prohibited. The standard permits the use of either the retrospective or cumulative effect transition method. This guidance will be applicable to the Company beginning on January 1, 2017. The Company is currently assessing the impact that adopting this new accounting guidance will have on its financial consolidated financial statements and footnote disclosures.

Reporting Discontinued Operations. In April 2014, the FASB issued an accounting standards update that changes the criteria for determining when disposals can be presented as discontinued operations and modifies discontinued operations disclosures. The new guidance now defines a discontinued operation as (i) a disposal of a component or group of components that is disposed of or is classified as held for sale and represents a strategic shift that has (or will have) a major effect on an entity s operations and financial results or (ii) an acquired business or nonprofit activity that is classified as held for sale on the date of acquisition. We will adopt this guidance and apply the disclosure requirements prospectively beginning on January 1, 2015.

Other accounting standards that have been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Company s financial position, results of operations and cash flows.

Note 3. Acquisitions and Divestitures

Acquisition-related costs are included in general and administrative expenses in the accompanying statements of operations for the periods indicated below (in thousands):

For the Nine Months Ended September 30,	
2014	**2013**
$5,480	$5,073

2014 Acquisitions

On July 1, 2014, MEMP consummated a transaction to acquire certain oil and natural gas liquids properties from a third party in Wyoming for an aggregate purchase price of approximately $911.7 million, including estimated post-closing adjustments (the Wyoming Acquisition). Revenues of $41.6 million were recorded in the statement of operations generated earnings of approximately $16.5 million related to the Wyoming Acquisition subsequent to the closing date.

On March 25, 2014, MEMP closed a transaction to acquire certain oil and natural gas producing properties from a third party in the Eagle Ford for approximately $168.1 million, including estimated customary post-closing adjustments (the Eagle Ford Acquisition). In addition, MEMP acquired a 30% interest in the seller s Eagle Ford leasehold. During the nine months ended September 30, 2014, revenues of approximately $25.9 million were recorded in the statement of operations related to the Eagle Ford Acquisition subsequent to the closing date and MEMP generated earnings of approximately $13.3 million.

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The following table summarizes the preliminary fair value assessment of the assets acquired and liabilities assumed as of the acquisition date (in thousands):

	Eagle Ford Acquisition	Wyoming Acquisition
Oil and gas properties	$ 168,606	$ 922,686
Asset retirement obligations	(285)	(3,328)
Revenue payable		(444)
Accrued liabilities	(250)	(7,237)
Total identifiable net assets	$ 168,071	$ 911,677

The following unaudited pro forma combined results of operations are provided for the nine months ended September 30, 2014 and 2013 as though the Wyoming Acquisition had been completed on January 1, 2013. The unaudited pro forma financial information was derived from the historical combined statements of operations of the Company and the previous owners and adjusted to include: (i) the revenues and direct operating expenses associated with oil and gas properties acquired, (ii) depletion expense applied to the adjusted basis of the properties acquired and (iii) interest expense on additional borrowings necessary to finance the acquisition. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of expected future results of operations.

	For the Nine Months Ended September 30,	
	2014	2013
	(In thousands, except per unit amounts)	
Revenues	$ 764,084	$ 561,359
Net income (loss)	(931,903)	218,870
Basic and diluted earnings per share	$ (4.94)	$

2014 Divestitures

On May 9, 2014, Golden Energy sold certain producing and non-producing properties in the Mississippian oil play of Northern Oklahoma to a third party for approximately $7.6 million, including estimated customary post-closing adjustments, and recorded a loss of $3.2 million.

2013 Acquisitions

On April 30, 2013, WildHorse Resources purchased certain oil and gas properties and leases in Louisiana from a third party for approximately $67.1 million.

MEMP closed two separate transactions during the nine months ended September 30, 2013 to acquire certain oil and natural gas properties from third parties in East Texas (the East Texas Acquisition) and the Rockies (the Rockies Acquisition) for approximately $29.4 million in aggregate. The East Texas Acquisition closed on September 6, 2013 and the Rockies Acquisition closed on August 30, 2013.

During the nine months ended September 30, 2013, Propel Energy acquired incremental interests in certain oil and gas properties and leases in the Hendrick Field located in Winkler County, Texas from third parties in three separate transactions for an aggregate purchase price of approximately $8.5 million.

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2013 Divestitures

On January 1, 2013, Tanos sold a natural gas gathering pipeline located in East Texas, which it had originally acquired in April 2010, to a privately held gas transportation company for a minimum purchase price of $1.5 million. The maximum allowable additional proceeds are $2.0 million. The contingent consideration is based on the natural gas pipeline servicing any new wells that Tanos drills in the area over the following three years. The contingent consideration portion of an arrangement is recorded when the consideration is determined to be realizable. Tanos recorded an aggregate gain of approximately $1.4 million related to this transaction, of which $0.4 million was contingent consideration. During the nine months ended September 30, 2013, Tanos also sold certain non-operated oil and gas properties for $2.9 million and recorded a gain of $1.4 million.

On May 10, 2013, Black Diamond entered into a purchase and sale agreement with a third party to sell certain of its Wyoming oil and gas properties with an estimated net book value of $39.8 million for $33.0 million, before customary adjustments. As a result, Black Diamond recorded a loss on the sale of $6.8 million. This transaction closed on June 4, 2013.

During the nine months ended September 30, 2013, BlueStone entered into an agreement with a third party to sell its remaining interest in certain properties in the Mossy Grove Prospect in Walker and Madison Counties located in East Texas. Total cash consideration received by BlueStone was approximately $117.9 million, which exceeded the net book value of the properties sold by $90.2 million. The transaction closed on July 31, 2013.

Note 4. Fair Value Measurements of Financial Instruments

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk. A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). All of the derivative instruments reflected on the accompanying balance sheets were considered Level 2.

The carrying values of accounts receivables, accounts payables (including accrued liabilities) and amounts outstanding under long-term debt agreements with variable rates included in the accompanying balance sheets approximated fair value at September 30, 2014 and December 31, 2013. The fair value estimates are based upon observable market data and are classified within Level 2 of the fair value hierarchy. These assets and liabilities are not presented in the following tables. See Note 8 for the estimated fair value of our outstanding fixed-rate debt.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The fair market values of the derivative financial instruments reflected on the balance sheets as of September 30, 2014 and December 31, 2013 were based on estimated forward commodity prices and forward interest rate yield curves. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement in its entirety. The significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

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The following table presents the gross derivative assets and liabilities that are measured at fair value on a recurring basis at September 30, 2014 and December 31, 2013 for each of the fair value hierarchy levels:

	Fair Value Measurements at September 30, 2014 Using			
	Quoted Prices in Active Market (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value
	(In thousands)			
Assets:				
Commodity derivatives	$	$ 129,711	$	$ 129,711
Interest rate derivatives		95		95
Total assets	$	$ 129,806	$	$ 129,806
Liabilities:				
Commodity derivatives	$	$ 74,542	$	$ 74,542
Interest rate derivatives		3,712		3,712
Total liabilities	$	$ 78,254	$	$ 78,254

	Fair Value Measurements at December 31, 2013 Using			
	Quoted Prices in Active Market (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value
	(In thousands)			
Assets:				
Commodity derivatives	$	$ 105,054	$	$ 105,054
Interest rate derivatives		884		884
Total assets	$	$ 105,938	$	$ 105,938
Liabilities:				
Commodity derivatives	$	$ 58,234	$	$ 58,234
Interest rate derivatives		5,590		5,590
Total liabilities	$	$ 63,824	$	$ 63,824

See Note 5 for additional information regarding our derivative instruments.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis as reflected on the balance sheets. The following methods and assumptions are used to estimate the fair values:

The fair value of asset retirement obligations (AROs) is based on discounted cash flow projections using numerous estimates, assumptions, and judgments regarding factors such as the existence of a legal obligation for an ARO; amounts and timing of settlements; the credit-adjusted risk-free rate; and inflation rates. See Note 6 for a summary of changes in AROs.

If sufficient market data is not available, the determination of the fair values of proved and unproved properties acquired in transactions accounted for as business combinations are prepared by utilizing estimates of discounted cash flow projections. The factors to determine fair value include, but are not limited to, estimates of: (i) economic reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital.

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Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

During the nine months ending September 30, 2014, we recognized $67.2 million of impairments primarily related to certain MEMP properties located in South Texas. The estimated future cash flows expected for these properties were compared to their carrying values and determined to be unrecoverable in part due to a downward revision of estimated proved reserves based on declining commodity prices and increased operating costs. We recognized impairment charges of less than $0.1 million on a consolidated basis for the nine months ending September 30, 2013.

Note 5. Risk Management and Derivative Instruments

Derivative instruments are utilized to manage exposure to commodity price and interest rate fluctuations and achieve a more predictable cash flow in connection with natural gas and oil sales from production and borrowing related activities. These instruments limit exposure to declines in prices or increases in interest rates, but also limit the benefits that would be realized if prices increase or interest rates decrease.

Certain inherent business risks are associated with commodity and interest derivative contracts, including market risk and credit risk. Market risk is the risk that the price of natural gas or oil will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the counterparty to a contract. It is our policy to enter into derivative contracts, including interest rate swaps, only with creditworthy counterparties, which generally are financial institutions, deemed by management as competent and competitive market makers. Some of the lenders, or certain of their affiliates, under our credit agreements are counterparties to our derivative contracts. While collateral is generally not required to be posted by counterparties, credit risk associated with derivative instruments is minimized by limiting exposure to any single counterparty and entering into derivative instruments only with creditworthy counterparties that are generally large financial institutions. Additionally, master netting agreements are used to mitigate risk of loss due to default with counterparties on derivative instruments. We have also entered into the International Swaps and Derivatives Association Master Agreements (ISDA Agreements) with each of our counterparties. The terms of the ISDA Agreements provide us and each of our counterparties with rights of set-off upon the occurrence of defined acts of default by either us or our counterparty to a derivative, whereby the party not in default may set-off all liabilities owed to the defaulting party against all net derivative asset receivables from the defaulting party. At September 30, 2014, after taking into effect netting arrangements, MEMP did not have any counterparty exposure related to its derivative instruments. Had certain counterparties failed completely to perform according to the terms of their existing contracts, MEMP would have the right to offset $37.5 million against amounts outstanding under its revolving credit facility at September 30, 2014. At September 30, 2014, after taking into effect netting arrangements, we did not have any counterparty exposure related to our derivative instruments. Had certain counterparties failed completely to perform according to the terms of their existing contracts, we would have the right to offset $29.0 million against amounts outstanding under our revolving credit facility at September 30, 2014. See Note 8 for additional information regarding our revolving credit facilities.

Commodity Derivatives

We may use a combination of commodity derivatives (e.g., floating-for-fixed swaps, put options, costless collars, call spreads and basis swaps) to manage exposure to commodity price volatility. We recognize all derivative instruments at fair value; however, certain of our put option derivative instruments have a deferred

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premium, which reduces the asset. For the deferred premium puts, the Company agrees to pay a premium to the counterparty at the time of settlement. At settlement, if the applicable index price is below the strike price of the put, the Company receives the difference between the strike price and the applicable index price multiplied by the contract volumes less the premium. If the applicable index price settles at or above the strike price of the put, the Company pays only the premium at settlement.

We enter into natural gas derivative contracts that are indexed to NYMEX-Henry Hub and regional indices such as NGPL TXOK, TETCO STX, TGT Z1, and Houston Ship Channel in proximity to our areas of production. We also enter into oil derivative contracts indexed to a variety of locations such as Inter-Continental Exchange (ICE) Brent, California Midway-Sunset and other regional locations. Our NGL derivative contracts are indexed to OPIS Mont Belvieu. At September 30, 2014, the MRD Segment had the following open commodity positions:

	Remaining 2014	2015	2016	2017	2018
Natural Gas Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (MMBtu)	4,540,000	2,250,000	1,670,000	1,270,000	1,500,000
Weighted-average fixed price	$ 4.18	$ 4.08	$ 4.18	$ 4.30	$ 4.30
Collar contracts:					
Average Monthly Volume (MMBtu)	730,000	1,580,000	1,100,000	1,050,000	
Weighted-average floor price	$ 4.11	$ 4.14	$ 4.00	$ 4.00	$
Weighted-average ceiling price	$ 5.15	$ 4.61	$ 4.71	$ 5.06	$
TGT Z1 basis swaps:					
Average Monthly Volume (MMBtu)	2,270,000	1,730,000	220,000	200,000	
Spread	$ (0.08)	$ (0.09)	$ (0.08)	$ (0.08)	$
Crude Oil Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (Bbls)	56,000	33,500		9,500	7,625
Weighted-average fixed price	$ 94.43	$ 93.86	$	$ 87.62	$ 87.00
Collar contracts:					
Average Monthly Volume (Bbls)	12,000	2,000	27,000		
Weighted-average floor price	$ 86.67	$ 85.00	$ 80.00	$	$
Weighted-average ceiling price	$ 112.33	$ 101.35	$ 99.70	$	$
Put option contracts:					
Average Monthly Volume (Bbls)		26,000			
Weighted-average fixed price	$	$ 85.00	$	$	$
Weighted-average deferred premium	$	$ (3.80)	$	$	$
NGL Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (Bbls)	184,000	151,000	148,500		
Weighted-average fixed price	$ 44.84	$ 41.61	$ 39.75	$	$

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At September 30, 2014, the MEMP Segment had the following open commodity positions:

	Remaining 2014	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (MMBtu)	2,580,200	2,605,278	2,692,442	2,450,067	2,160,000	1,914,583
Weighted-average fixed price	$ 4.34	$ 4.28	$ 4.40	$ 4.31	$ 4.51	$ 4.75
Collar contracts:						
Average Monthly Volume (MMBtu)	340,000	350,000				
Weighted-average floor price	$ 5.00	$ 4.62	$	$	$	$
Weighted-average ceiling price	$ 6.31	$ 5.80	$	$	$	$
Call spreads (1):						
Average Monthly Volume (MMBtu)	120,000	80,000				
Weighted-average sold strike price	$ 5.17	$ 5.25	$	$	$	$
Weighted-average bought strike price	$ 6.53	$ 6.75	$	$	$	$
Basis swaps:						
Average Monthly Volume (MMBtu)	2,830,000	2,940,000	1,635,000	300,000		
Spread	$ (0.09)	$ (0.12)	$ (0.06)	$ (0.05)	$	$
Crude Oil Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	283,452	314,281	332,813	326,600	312,000	160,000
Weighted-average fixed price	$ 95.83	$ 90.96	$ 85.83	$ 84.38	$ 83.74	$ 85.52
Collar contracts:						
Average Monthly Volume (Bbls)	23,000	5,000				
Weighted-average floor price	$ 82.83	$ 80.00	$	$	$	$
Weighted-average ceiling price	$ 105.31	$ 94.00	$	$	$	$
Basis swaps:						
Average Monthly Volume (Bbls)	134,000	97,500				
Spread	$ (4.32)	$ (7.07)	$	$	$	$
NGL Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	167,500	149,200	55,000			
Weighted-average fixed price	$ 43.13	$ 43.02	$ 39.28	$	$	$

(1) These transactions were entered into for the purpose of eliminating the ceiling portion of certain collar arrangements, which effectively converted the applicable collars into swaps.

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The MEMP Segment basis swaps included in the table above is presented on a disaggregated basis below:

	Remaining 2014	2015	2016	2017
Natural Gas Derivative Contracts:				
NGPL TexOk basis swaps:				
Average Monthly Volume (MMBtu)	2,260,000	2,280,000	1,500,000	300,000
Spread	$ (0.09)	$ (0.11)	$ (0.07)	$ (0.05)
NGPL STX basis swaps:				
Average Monthly Volume (MMBtu)	380,000			
Spread	$ (0.11)	$	$	$
HSC basis swaps:				
Average Monthly Volume (MMBtu)	190,000	150,000	135,000	
Spread	$ (0.07)	$ (0.08)	$ 0.07	$
CIG basis swaps:				
Average Monthly Volume (MMBtu)		210,000		
Spread	$	$ (0.25)	$	$
TETCO STX basis swaps:				
Average Monthly Volume (MMBtu)		300,000		
Spread	$	$ (0.09)	$	$
Crude Oil Derivative Contracts:				
Midway-Sunset basis swaps:				
Average Monthly Volume (Bbls)	60,000	57,500		
Spread Brent	$ (9.25)	$ (9.73)	$	$
Midland basis swaps:				
Average Monthly Volume (Bbls)	40,000	40,000		
Spread WTI	$ (3.68)	$ (3.25)	$	$
LLS Crude basis swaps:				
Average Monthly Volume (Bbls)	34,000			
Spread WTI	$ 3.61	$	$	$

Interest Rate Swaps

Periodically, we enter into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates such as those in our credit agreement to fixed interest rates. From time to time we enter into offsetting positions to avoid being economically over-hedged. At September 30, 2014, we had the following interest rate swap open positions:

Credit Facility	**Remaining 2014**	**2015**	**2016**

MEMP:			
Average Monthly Notional (in thousands)	$ 248,333	$ 280,833	$ 150,000
Weighted-average fixed rate	1.299%	1.416%	1.193%
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR

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On July 1, 2014, we elected to terminate the interest rate swaps associated with the MRD credit facility and in the aggregate paid our counterparties approximately $0.7 million. WildHorse Resources novated the interest rate swaps to MRD in connection with the closing of our initial public offering.

Balance Sheet Presentation

The following table summarizes both: (i) the gross fair value of derivative instruments by the appropriate balance sheet classification even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the balance sheet and (ii) the net recorded fair value as reflected on the balance sheet at September 30, 2014 and December 31, 2013. There was no cash collateral received or pledged associated with our derivative instruments since most of the counterparties, or certain of their affiliates, to our derivative contracts are lenders under our collective credit agreements.

		Asset Derivatives		Liability Derivatives	
Type	**Balance Sheet Location**	**September 30, 2014**	**December 31, 2013**	**September 30, 2014**	**December 31, 2013**
		(In thousands)			
Commodity contracts	Short-term derivative instruments	$ 48,405	$ 21,759	$ 12,458	$ 19,739
Interest rate swaps	Short-term derivative instruments		845	3,635	3,287
Gross fair value		48,405	22,604	16,093	23,026
Netting arrangements	Short-term derivative instruments	(10,984)	(13,315)	(10,984)	(13,315)
Net recorded fair value	Short-term derivative instruments	$ 37,421	$ 9,289	$ 5,109	$ 9,711
Commodity contracts	Long-term derivative instruments	$ 81,306	$ 83,295	$ 62,084	$ 38,495
Interest rate swaps	Long-term derivative instruments	95	39	77	2,303
Gross fair value		81,401	83,334	62,161	40,798
Netting arrangements	Long-term derivative instruments	(46,886)	(34,718)	(46,886)	(34,718)
Net recorded fair value	Long-term derivative instruments	$ 34,515	$ 48,616	$ 15,275	$ 6,080

(Gains) Losses on Derivatives

All gains and losses, including changes in the derivative instruments fair values, have been recorded in the accompanying statements of operations since derivative instruments are not designated as hedging instruments for accounting and financial reporting purposes. The following table details the gains and losses related to derivative instruments for the nine months ended September 30, 2014 and 2013 (in thousands):

	Statements of Operations Location	**For the Nine Months Ended September 30,**	
		2014	**2013**
Commodity derivative contracts	(Gain) loss on commodity derivatives	$ 11,580	$ (29,556)
Interest rate derivatives	Interest expense, net	1,157	69

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Note 6. Asset Retirement Obligations

Asset retirement obligations primarily relate to our portion of future plugging and abandonment costs for wells and related facilities.

The following table presents the changes in the asset retirement obligations for the nine months ended September 30, 2014 (in thousands):

Asset retirement obligations at beginning of period	$ 111,769
Liabilities added from acquisitions or drilling	5,053
Liabilities removed upon sale of wells to an affiliate	(1,636)
Liabilities removed upon plugging and abandoning	(344)
Revisions	67
Accretion expense	4,601
Asset retirement obligations at end of period	$ 119,510

Note 7. Restricted Investments

Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with offshore Southern California oil and gas properties owned by MEMP.

The components of the restricted investment balance consisted of the following at the dates indicated:

	September 30, 2014	December 31, 2013
	(In thousands)	
BOEM platform abandonment (See Note 15)	$ 68,970	$ 66,373
BOEM lease bonds	794	794
SPBPC Collateral:		
Contractual pipeline and surface facilities abandonment	2,592	2,306
California State Lands Commission pipeline right-of-way bond	3,005	3,005
City of Long Beach pipeline facility permit	500	500
Federal pipeline right-of-way bond	307	307
Port of Long Beach pipeline license	100	100

Restricted investments	$ 76,268	$ 73,385

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Note 8. Long Term Debt

The following table presents our consolidated and combined debt obligations at the dates indicated:

	September 30, 2014	December 31, 2013
	(In thousands)	
MRD Segment:		
MRD $2.0 billion revolving credit facility, variable-rate, due June 2019	$ 28,000	$
WildHorse Resources $1.0 billion revolving credit facility, variable-rate, terminated June 2014		203,100
WildHorse Resources $325.0 million second lien term facility, variable-rate, terminated June 2014		325,000
10.00%/10.75% senior PIK toggle notes redeemed June 2014(1)		350,000
5.875% senior unsecured notes, due July 2022(2)	600,000	
10.00%/10.75% senior PIK toggle notes unamortized discounts		(6,950)
Subtotal	628,000	871,150
MEMP Segment:		
MEMP $2.0 billion revolving credit facility, variable-rate, due March 2018	301,000	103,000
7.625% senior notes, fixed-rate, due May 2021(3)	700,000	700,000
6.875% senior unsecurred notes, due August 2022(4)	500,000	
Unamortized discounts	(17,200)	(10,933)
Subtotal	1,483,800	792,067
Total long-term debt	$ 2,111,800	$ 1,663,217

(1) The estimated fair value of this fixed-rate debt was $348.3 million at December 31, 2013. The estimated fair value is based on quoted market prices and is classified as Level 2 within the fair value hierarchy.
(2) The estimated fair value of this fixed-rate debt was $582.0 million September 30, 2014. The estimated fair value is based on quoted market prices and is classified as Level 2 within the fair value hierarchy.
(3) The estimated fair value of this fixed-rate debt was $700.0 million and $721.0 million at September 30, 2014 and December 31, 2013, respectively. The estimated fair value is based on quoted market prices and is classified as Level 2 within the fair value hierarchy.
(4) The estimated fair value of this fixed-rate debt was $475.0 million at September 30, 2014. The estimated fair value is based on quoted market prices and is classified as Level 2 within the fair value hierarchy.

Borrowing Base

Credit facilities tied to borrowing bases are common throughout the oil and gas industry. Each of the revolving credit facilities borrowing base is subject to redetermination on at least a semi-annual basis primarily based on estimated proved reserves. The borrowing base for each credit facility was the following at the date indicated (in thousands):

	September 30, 2014
MRD Segment:	
MRD $2.0 billion revolving credit facility, variable-rate, due June 2019	$ 668,500
MEMP Segment:	
MEMP $2.0 billion revolving credit facility, variable-rate, due March 2018	1,315,000

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Subsequent events. On October 3, 2014, the borrowing base under the MRD revolving credit facility was increased to $725.0 million, and we entered into an amendment to the credit agreement to, among other things, permit us to hedge a larger portion of our anticipated production from our proved reserves. On October 10, 2014, MEMP s borrowing base under its revolving credit facility was redetermined and increased to $1.44 billion.

MRD Revolving Credit Facility

On June 18, 2014, we, as borrower, and certain of our subsidiaries, as guarantors, entered into a revolving credit facility, which is a five-year, $2.0 billion revolving credit facility with an initial borrowing base of $725.0 million and aggregate elected commitments of $725.0 million.

We are permitted to borrow under the revolving credit facility in an amount up to the least of (i) the face amount of our revolving credit facility, (ii) the borrowing base and (iii) the aggregate elected commitments. The revolving credit facility is reserve-based, and thus our borrowing base is primarily based on the estimated value of our oil, NGL and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. Our borrowing base is subject to redetermination on a semi-annual basis based on an engineering report with respect to our estimated oil, NGL and natural gas reserves, which will take into account the prevailing oil, NGL and natural gas prices at such time, as adjusted for the impact of our commodity derivative contracts. Unanimous approval by the lenders is required for any increase to the borrowing base. In addition, we may, subject to certain conditions, increase our aggregate elected commitments in an amount not to exceed the then effective borrowing base on or following a scheduled redetermination of our borrowing base once before the next scheduled redetermination date.

Borrowings under the revolving credit facility are secured by liens on substantially all of our properties, but in any event, not less than 80% of the total value of our oil and natural gas properties, and all of our equity interests in any future guarantor subsidiaries and all of our other assets including personal property. Additionally, borrowings bear interest, at our option, at either (i) the greatest of (x) the prime rate as determined by the administrative agent, (y) the federal funds effective rate plus 0.50%, and (z) the one-month adjusted LIBOR plus 1.0% (adjusted upwards, if necessary, to the next 1/100th of 1%), in each case, plus a margin that varies from 0.50% to 1.50% per annum according to the total commitment usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 1.50% to 2.50% per annum according to the total commitment usage. The unused portion of the total commitments is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to our total commitments usage.

The revolving credit facility requires maintenance of a ratio of Consolidated EBITDAX to Consolidated Net Interest Expense (as each term is determined under the revolving credit facility), which we refer to as the interest coverage ratio, of not less than 2.5 to 1.0, and a ratio of consolidated current assets to consolidated current liabilities, each as determined under the revolving credit facility, which we refer to as the current ratio, of not less than 1.0 to 1.0.

Additionally, the revolving credit facility contains various covenants and restrictive provisions that, among other things, limit our ability to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of our assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of our production and prepay certain indebtedness.

Events of default under the revolving credit facility include, but are not limited to, failure to make payments when due, breach of any covenant continuing beyond the applicable cure period, default under any other material

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debt, change in management or change of control, bankruptcy or other insolvency event and certain material adverse effects on our business.

MRD 5.875% Senior Unsecured Notes Offering

On July 10, 2014, the Company completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes (the MRD Senior Notes) at par. The MRD Senior Notes will mature on July 1, 2022. Interest on the MRD Senior Notes will accrue from July 10, 2014 and will be payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2015. The MRD Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of our existing subsidiaries. The MRD Senior Notes and the guarantees of the MRD Senior Notes will rank equally with our and the guarantors existing and future senior indebtedness, will be effectively junior to all of our and the guarantors existing and future secured indebtedness (to the extent of the value of the assets securing such indebtedness), and senior in right of payment to all of our and the guarantors subordinated indebtedness. The MRD Senior Notes will be structurally subordinated to the indebtedness and other liabilities of our non-guarantor subsidiaries, including MEMP and its subsidiaries and MEMP GP.

The MRD Senior Notes are governed by an indenture dated as of July 10, 2014. The MRD Senior Notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any, to the date of redemption. The Company may also be required to repurchase the MRD Senior Notes upon a change of control. The indenture contains customary covenants and restrictive provisions, many of which will terminate if at any time no default exists under the indenture and the MRD Senior Notes receive an investment grade rating from both of two specified ratings agencies. MEMP and its subsidiaries are not subject to these covenants. The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to either the Company or the guarantors, all outstanding MRD Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding MRD Senior Notes may declare all the MRD Senior Notes to be due and payable immediately.

PIK notes

On December 18, 2013, MRD LLC and its wholly-owned subsidiary Memorial Resource Finance Corp. (MRD Finance Corp. and, together with MRD LLC, the MRD Issuers) completed a private placement of $350.0 million in aggregate principal amount of the PIK notes. The PIK notes were issued at 98% of par with a maturity date of December 15, 2018. Net proceeds from the private offering were used: (i) to repay all indebtedness then outstanding under MRD LLC s then-existing revolving credit facility, (ii) to establish a cash reserve of $50.0 million for the payment of interest on the PIK notes, (iii) to pay a $210.0 million distribution to the Funds, and (iv) for general company purposes. Interest on the PIK notes was payable semi-annually in arrears on June 15 and December 15 of each year, commencing on June 15, 2014.

A redemption notice was delivered to the PIK notes trustee on June 16, 2014, which specified a redemption date of July 16, 2014 at a redemption price of 102% of the principal amount of the PIK notes plus accrued and unpaid interest thereon to the date of redemption. In connection with the closing of our initial public offering, we assumed the obligations of MRD LLC under the PIK notes indenture and the related debt security agreement. We irrevocably deposited with the PIK notes trustee approximately $360.0 million on June 27, 2014, which was an amount sufficient to fund the redemption of the PIK notes on the redemption date and to satisfy and discharge our obligations under the PIK notes and the related indenture. The discharge became effective upon the irrevocable deposit of the funds with the PIK notes trustee. An extinguishment loss of $23.6 million was recognized related to the redemption of the PIK notes.

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WildHorse Resources Revolving Credit Facility and Second Lien Facility

On April 3, 2013, WildHorse Resources entered into an amended and restated credit agreement. This revolving credit facility provided for aggregate maximum credit amounts at any time of $1.0 billion, consisting of borrowings and letters of credit and had an initial borrowing base of $300.0 million. This revolving credit facility was due to mature on April 13, 2018. The borrowing base was subject to redetermination on at least a semi-annual basis. Borrowings under the revolving credit facility were to be secured by liens on substantially all of WildHorse Resources properties, but in any event, not less than 80% of the total value of the WildHorse Resources oil and natural gas properties.

On June 13, 2013, WildHorse Resources entered into a $325.0 million second lien term loan agreement that was due to mature on December 13, 2018. Borrowings bore interest, at the borrower s option, at either: (i) the Alternative Base Rate (as defined within each credit facility) plus 5.25% per annum or (ii) the applicable LIBOR plus 6.25% per annum. Borrowings under the second lien term loan agreement were to be secured by second-priority liens on substantially all of WildHorse Resources properties, but in any event, not less than 80% of the total value of the WildHorse Resources oil and natural gas properties. The priority of the security interests in the collateral and related creditors rights was set forth in an intercreditor agreement. The second lien term loan agreement contained customary affirmative and negative covenants, restrictive provisions and events of default.

On June 13, 2013, WildHorse Resources borrowed $325.0 million under its second lien term loan agreement and used such borrowings to reduce outstanding indebtedness under its revolving credit facility and to pay a onetime special $225.0 million distribution to MRD LLC. This $225.0 million distribution was subsequently distributed to the Funds.

In connection with the closing of our initial public offering, the WildHorse Resources revolving credit facility and second lien term loan were repaid in full and terminated. An extinguishment loss of $13.7 million was recognized related to the termination of the revolving credit facility and second lien term loan.

MEMP Revolving Credit Facility & Senior Notes

Memorial Production Operating LLC (OLLC), a wholly-owned subsidiary of MEMP, is a party to a $2.0 billion revolving credit facility, which is guaranteed by MEMP and all of its current and future subsidiaries (other than certain immaterial subsidiaries).

Borrowings under the revolving credit facility are secured by liens on substantially all of MEMP s properties, but in any event, not less than 80% of the total value of MEMP s oil and natural gas properties, and all of MEMP s equity interests in OLLC and any future guarantor subsidiaries (other than San Pedro Bay Pipeline Company) and all of MEMP s other assets including personal property. Additionally, borrowings under the revolving credit facility bear interest, at MEMP s option, at: (i) the Alternative Base Rate defined as the greatest of (x) the prime rate as determined by the administrative agent, (y) the federal funds effective rate plus 0.50%, and (z) the one-month adjusted LIBOR plus 1.0% (adjusted upwards, if necessary, to the next 1/100th of 1%), in each case, plus a margin that varies from 0.50% to 1.50% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), (ii) the applicable LIBOR plus a margin that varies from 1.50% to 2.50% per annum according to the borrowing base usage, or (iii) the applicable LIBOR Market Index plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. The unused portion of the borrowing base (or, if lower, the reduced commitment amount that has been elected) will be subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

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On April 17, 2013, May 23, 2013 and October 10, 2013, MEMP and its wholly-owned subsidiary Memorial Production Finance Corporation (Finance Corp. and, together with MEMP, the MEMP Issuers) completed a private placement of $300.0 million, $100.0 million and $300.0 million, respectively, of their 7.625% senior unsecured notes due 2021 (the 2021 Senior Notes). The 2021 Senior Notes are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by all of the MEMP s subsidiaries (other than Finance Corp., which is co-issuer of the 2021 Senior Notes, and certain immaterial subsidiaries). The 2021 Senior Notes will mature on May 1, 2021 with interest accruing at a rate of 7.625% per annum and payable semi-annually in arrears on May 1 and November 1 of each year. The 2021 Senior Notes are governed by an indenture. The 2021 Senior Notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any. The MEMP Issuers may also be required to repurchase the 2021 Senior Notes upon a change of control. The indenture contains customary covenants and restrictive provisions, many of which will terminate if at any time no default exists under the indenture and the 2021 Senior Notes receive an investment grade rating from both of two specified ratings agencies. The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to either of the MEMP Issuers, all outstanding 2021 Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 2021 Senior Notes may declare all the 2021 Senior Notes to be due and payable immediately.

On July 17, 2014, the MEMP Issuers completed a private placement of $500.0 million aggregate principal amount of 6.875% senior unsecured notes (the 2022 Senior Notes). The 2022 Senior Notes were issued at 98.485% of par and are fully and unconditionally guaranteed (subject to customary release provisions on a joint and several basis by all of MEMP s subsidiaries other than Finance Corp., which is co-issuer of the 2022 Senior Notes, and certain immaterial subsidiaries). The 2022 Senior Notes will mature on August 1, 2022 with interest accruing at 6.875% per annum and payable semi-annually in arrears on February 1 and August 1of each year, commencing on February 1, 2015. The indenture governing the 2022 Notes, dated as July 17, 2014, contains customary covenants and restrictive provisions, many of which will terminate if at any time no default exists under the indenture and the 2022 Senior Notes receive an investment grade rating from both of two specified ratings agencies. The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to either of the MEMP Issuers, all outstanding 2022 Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 2022 Senior Notes may declare all the 2022 Senior Notes to be due and payable immediately. The net proceeds from the notes offering of approximately $484.9 million, after deducting the initial purchasers discounts and commissions but before estimated offering expenses, were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility and for general partnership purposes.

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Weighted-Average Interest Rates

The following table presents the weighted-average interest rates paid on our consolidated and combined variable-rate debt obligations for the periods presented:

Credit Facility	For the Nine Months Ended September 30, 2014	2013
MRD Segment:		
MRD revolving credit facility	2.40%	n/a
MRD LLC revolver terminated December 2013	n/a	3.20%
WildHorse Resources revolver terminated June 2014	4.04%	3.44%
WildHorse Resources second lien terminated June 2014	6.44%	6.50%
Black Diamond terminated November 2013	n/a	3.34%
MEMP Segment:		
MEMP revolving credit facility	2.08%	2.55%
WHT revolver terminated March 2013	n/a	2.29%
Tanos revolver terminated April 2013	n/a	2.12%
Stanolind revolver paid off by MEMP October 2013	n/a	3.52%
Boaz revolver terminated October 2013	n/a	2.97%
Crown revolver terminated October 2013	n/a	3.38%
Propel Energy revolver paid off by MEMP October 2013	n/a	3.08%

Unamortized Deferred Financing Costs

Unamortized deferred financing costs associated with our consolidated and combined debt obligations were as follows at the dates indicated:

	September 30, 2014	December 31, 2013
	(In thousands)	
MRD Segment:		
MRD revolving credit facility	$ 4,433	$
MRD senior notes	12,825	
WildHorse Resources revolving credit facility		2,436
WildHorse Resources second lien term loan		9,030
PIK notes		8,261
MEMP Segment:		
MEMP revolving credit facility	6,882	5,413
2021 Senior Notes	13,836	15,053
2022 Senior Notes	8,222	

	$ 46,198	$ 40,193

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Note 9. Stockholders Equity and Noncontrolling Interests

Common Stock

The Company s authorized capital stock includes 600,000,000 shares of common stock, $0.01 par value per share. The following is a summary of the changes in our common shares issued for the nine months ended September 30, 2014:

Balance January 1, 2014	
Shares of common stock issued in connection with restructuring transactions (Note 1)	171,000,000
Shares of common stock issued sold in initial public offering (Note 1)	21,500,000
Restricted common shares issued (Note 11)	1,068,422
Restricted common shares forfeited	(9,211)
Balance September 30, 2014	193,559,211

See Note 11 for additional information regarding restricted common shares that were granted in connection with our initial public offering. Restricted shares of common stock are considered issued and outstanding on the grant date of restricted stock award.

Preferred Stock

Our amended and restated certificate of incorporation authorizes our board of directors (Board), subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of preferred stock, par value $0.01 per share, covering up to an aggregate of 50,000,000 shares of preferred stock. There are no shares issued and outstanding as of September 30, 2014.

Dividend Policy

We do not anticipate declaring or providing any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain all future earnings, if any, for use in the operation of our business and to fund future growth. The decision whether to pay dividends in the future will be made by our Board in light of conditions then existing, including factors such as our financial condition, earnings, available cash, business opportunities, legal requirements, restrictions in our debt agreements, and other contracts and other factors our Board deems relevant.

Noncontrolling Interests

Noncontrolling interests is the portion of equity ownership in the Company s consolidated subsidiaries not attributable to the Company and primarily consists of the equity interests held by: (i) the limited partners of MEMP, including the subordinated units currently held by MRD Holdco, and (ii) a third party investor in the San Pedro Bay Pipeline Company. Prior to our initial public offering, certain current or former key employees of certain of MRD LLC s subsidiaries also held equity interests in those subsidiaries.

Distributions paid to the limited partners of MEMP primarily represent the quarterly cash distributions paid to MEMP s unitholders, excluding those paid to MRD LLC.

Contributions received from limited partners of MEMP primarily represent net cash proceeds received from common unit offerings.

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On March 25, 2013, MEMP sold 9,775,000 of its common units in an underwritten equity offering, which generated net cash proceeds of $171.8 million after deducting underwriting discounts and offering expenses. The net proceeds from this equity offering partially funded MEMP s acquisition of all of the outstanding equity interests in WHT.

On July 15, 2014, MEMP sold 9,890,000 common units representing limited partner interests in MEMP (including 1,290,000 common units purchased pursuant to the full exercise of the underwriters option to purchase additional common units) to the underwriters at a negotiated price of $22.25 per unit generating total net proceeds of approximately $220.0 million after deducting offering expenses. The net proceeds from the equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility.

On September 9, 2014, MEMP issued 14,950,000 common units representing limited partner interests in MEMP (including 1,950,000 common units purchased pursuant to the full exercise of the underwriters option to purchase additional common units) to the public at an offering price of $22.29 per unit generating total net proceeds of approximately $321.6 million after deducting underwriting discounts and offering expenses. The net proceeds from the equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility.

On April 1, 2013, Tanos management team sold its 1.066% interest in Tanos to MRD LLC and all incentive units held were forfeited. See Note 12 for further information.

In connection with the our initial public offering, certain former management members of WildHorse Resources contributed their 0.1% membership interest in WildHorse Resources as well as their incentive units in exchange for shares of our common stock and cash consideration of $30.0 million. The difference between the carrying amount of the noncontrolling interest of $0.4 million and the fair value of the consideration paid of $3.3 million was recognized directly in stockholders equity as additional paid in capital. See Note 12 for further information.

Note 10. Earnings per Share

The following sets forth the calculation of earnings (loss) per share, or EPS, for the periods indicated (in thousands, except per share amounts):

	For the Nine Months Ended September 30, 2014
Numerator:	
Net income (loss) available to common stockholders	$ (951,801)
Denominator:	

Weighted average common shares outstanding		192,500
Restricted common shares(1)		
Weighted average common and common equivalent shares outstanding		192,500
Basic EPS	$	(4.94)
Diluted EPS	$	(4.94)

(1) The treasury stock method is applied to determine the dilutive effect of the unvested restricted common shares. The restricted common shares were antidilutive due to net losses and excluded from the diluted EPS calculation for the nine months ending September 30, 2014. There were 206,956 incremental shares excluded from the computation of diluted EPS for the nine months ending September 30, 2014.

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Our supplemental basic and diluted EPS includes earnings allocated to both previous owners and MRD LLC members for all periods presented due to common control considerations. The following sets forth the calculation of our supplemental EPS, for the periods indicated (in thousands, except per share amounts):

	For the Nine Months Ended September 30, 2014
Numerator:	
Net income (loss) attributable to Memorial Resource Development Corp.	$ (930,071)
Denominator:	
Weighted average common shares outstanding	192,500
Restricted common shares(1)	
Weighted average common and common equivalent shares outstanding	192,500
Basic EPS	$ (4.83)
Diluted EPS	$ (4.83)

(1) The treasury stock method is applied to determine the dilutive effect of the unvested restricted common shares. The restricted common shares were antidilutive due to net losses and excluded from the diluted EPS calculation for the nine months ending September 30, 2014. There were 206,956 incremental shares excluded from the computation of diluted EPS for the nine months ending September 30, 2014.

Note 11. Long-Term Incentive Plans

MRD

In June 2014, our Board adopted the Memorial Resource Development Corp. 2014 Long Term Incentive Plan (MRD LTIP) for the employees of the Company and the Board. The MRD LTIP became effective upon filing of a registration statement on Form S-8 with the SEC on June 18, 2014. The MRD LTIP provides for potential grants of stock options, stock appreciation rights, restricted stock awards, restricted stock units, bonus stock, dividend equivalents, performance awards, annual incentive awards, and other stock-based awards. The MRD LTIP initially limits the number of common shares that may be delivered pursuant to awards under the plan to 19,250,000 common shares. Common shares that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The MRD LTIP will be administered by our Board or a committee thereof.

In connection with our initial public offering, our Board approved an aggregate award of 1,052,633 shares of restricted stock under the MRD LTIP to certain of our key employees, including each of our executive officers. These restricted stock awards will vest ratably on a four-year annual vesting schedule from the date of the grant and are subject to restrictions on transferability and customary forfeiture provisions. An award of 5,263 shares of restricted stock was also granted to each of our independent directors. These restricted stock awards will vest one year from the date of the grant and are also subject to restrictions on transferability and customary forfeiture provisions.

Award recipients are entitled to all the rights of absolute ownership of the restricted common shares, including the right to vote those shares and to receive dividends thereon if, as, and when declared by our Board. The term restricted common share represents a time-vested share. Such awards are non-vested until the required service period expires.

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The following table summarizes information regarding restricted common share awards granted under the MRD LTIP for the periods presented:

	Number of Shares	Weighted-Average Grant Date Fair Value per Share(1)
Restricted common shares outstanding at December 31, 2013		$
Granted(2)	1,068,422	$ 19.00
Forfeited	(9,211)	$ 19.00
Restricted common units outstanding at September 30, 2014	1,059,211	$ 19.00

(1) Determined by dividing the aggregate grant date fair value of awards issued.
(2) The aggregate grant date fair value of restricted common share awards issued in 2014 was $20.3 million based on a grant date market price of $19.00 per share.

The following table summarizes the amount of recognized compensation expense associated with these awards that are reflected in the accompanying statements of operations for the periods presented (in thousands):

For the Nine Months Ended September 30, 2014	2013
$1,487	$

The unrecognized compensation cost associated with restricted common share awards was $18.6 million at September 30, 2014. We expect to recognize the unrecognized compensation cost for these awards over a weighted-average period of 3.68 years.

MEMP

In December 2011, the Memorial Production Partners GP LLC Long-Term Incentive Plan (MEMP LTIP) was adopted for employees, officers, consultants and directors of MEMP GP and any of its affiliates who perform services for MEMP. The MEMP LTIP consists of restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, other unit-based awards and unit awards. The MEMP LTIP initially limits the number of common units that may be delivered pursuant to awards under the plan to 2,142,221 common units. Common units that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards.

The restricted common units awarded are subject to restrictions on transferability, customary forfeiture provisions and graded vesting provisions. One-third of each award generally vests on the first, second, and third anniversaries of the date of grant. Award recipients have all the rights of a unitholder in MEMP with respect to the restricted common units, including the right to receive distributions thereon if and when distributions are made by MEMP to its unitholders (except with respect to the fourth quarter 2011 distribution that was paid in February 2012). The term restricted common unit represents a time-vested unit. Such awards are non-vested until the required service period expires.

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The following table summarizes information regarding restricted common unit awards granted under the MEMP LTIP for the periods presented:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit(1)
Restricted common units outstanding at December 31, 2013	706,927	$ 18.62
Granted(2)	684,954	$ 22.39
Forfeited	(36,112)	$ 20.43
Vested	(260,067)	$ 18.56
Restricted common units outstanding at September 30, 2014	1,095,702	$ 20.93

(1) Determined by dividing the aggregate grant date fair value of awards issued.
(2) The aggregate grant date fair value of restricted common unit awards issued in 2014 was $15.3 million based on a grant date market price range of $21.99 $23.40 per unit

The following table summarizes the amount of recognized compensation expense associated with these awards that are reflected in the accompanying statements of operations for the periods presented (in thousands):

For the Nine Months Ended September 30, 2014	2013
$5,387	$2,322

The unrecognized compensation cost associated with restricted common unit awards was $19.1 million at September 30, 2014. We expect to recognize the unrecognized compensation cost for these awards over a weighted-average period of 2.3 years. Since the restricted common units are participating securities, distributions received by the restricted common unitholders are generally included in distributions to noncontrolling interests as presented on our unaudited condensed statements of consolidated and combined cash flows.

Note 12. Incentive Units

General

Each of the governing documents of BlueStone, Tanos, WildHorse Resources, Classic, Black Diamond and MRD LLC previously provided for the issuance of incentive units. The incentive units were subject to performance conditions that affected their vesting. Compensation cost was recognized only if the performance condition was probable of being satisfied at each reporting date.

BlueStone, Tanos, WildHorse Resources, Classic, Black Diamond and MRD LLC each granted incentive units to certain of its members who were key employees at the time of grant. Holders of incentive units were entitled to distributions ranging from 10% to 31.5% when declared, but only after cumulative distribution thresholds (payouts) had been achieved. Payouts were generally triggered after the recovery of specified members capital contributions plus a rate of return. In connection with MEMP s initial public offering in December 2011, BlueStone s Special Tier and Tier I unit holders vested in their respective awards. Tier I unit holders became eligible to participate in 16.5% of any future distributions made by BlueStone.

Vesting of the incentive units was generally dependent upon an explicit service period, a fundamental change as defined in the respective governing document, and achievement of payout. All incentive units not

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vested were forfeited if an employee was no longer employed. All incentive units were forfeited if a holder resigned whether the incentive units were vested or not. If the payouts had not yet occurred, then all incentive units, whether or not vested, were forfeited automatically (unless extended).

On April 1, 2013, Tanos management team sold its 1.066% interest in Tanos to Memorial Resource and all incentive units held were forfeited. Compensation expense of approximately $5.8 million was recorded by Tanos and recognized as a component of general and administrative expense during the nine months ended September 30, 2013.

Compensation expense of approximately $1.0 million and $19.1 million was recorded by BlueStone (see Note 3) and recognized as a component of incentive unit compensation expense during the nine months ended September 30, 2014 and 2013, respectively.

In connection with the our initial public offering, certain former management members of WildHorse Resources contributed their 0.1% membership interest in WildHorse Resources as well as their incentive units in exchange for 42,334,323 shares of our common stock and cash consideration of $30.0 million. The portion of the total consideration related to acquiring the 0.1% membership interest was accounted for as the acquisition of noncontrolling interests. The difference between the carrying amount of the noncontrolling interest of $0.4 million and the fair value of the consideration paid of $3.3 million was recognized directly in stockholders equity as additional paid in capital. Compensation expense of approximately $831.1 million was recognized as a component of incentive unit compensation expense during the nine months ended September 30, 2014 related to the incentive units, of which approximately $26.7 million was paid in cash and the remaining $804.4 million related to the issuance of our common stock.

MRD Holdco

MRD LLC incentive units were originally granted in June 2012 and February 2013. In connection with our initial public offering and the related restructuring transactions, these incentive units were exchanged for substantially identical units in MRD Holdco, and such incentive units entitle holders thereof to portions of future distributions by MRD Holdco. MRD Holdco s governing documents authorize the issuance of 1,000 incentive units, of which 930 incentive units were granted in an exchange for the cancelled MRD LLC awards (the Exchanged Incentive Units).

The holders of the Exchanged Incentive Units are eligible to participate in 9.3% of any future distributions made by MRD Holdco. The payment likelihood was deemed probable as a result of our initial public offering and the reasonable expectation that MRD Holdco will monetize the shares of our common stock it owns over an estimated three year period as market conditions permit. We recognized $136.7 million of compensation expense offset by a deemed capital contribution from MRD Holdco and the unrecognized compensation expense of approximately $158.5 million as of September 30, 2014 will be recognized over the remaining expected service period. The fair value of the Exchanged Incentive Units will be remeasured on a quarterly basis until all payments have been made. The settlement obligation rests with MRD Holdco. Accordingly, no payments will ever be made by us related to these incentive units; however, non-cash compensation expense will be allocated to us in future periods offset by capital contributions. As such, these awards are not dilutive to our stockholders.

Subsequent to our initial public offering, MRD Holdco granted the remaining 70 incentive units to certain key employees (the Subsequent Incentive Units). The holders of the Subsequent Incentive Units are eligible to participate in 0.7% of any future distributions made by MRD Holdco once payout associated with these incentive units has been achieved. The payment likelihood was deemed probable at September 30, 2014 as a result of our

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initial public offering and the reasonable expectation that MRD Holdco will monetize the shares of our common stock it owns over an estimated three year period as market conditions permit. We recognized $0.6 million of compensation expense and the unrecognized compensation expense of approximately $5.3 million as of September 30, 2014 will be recognized over the remaining expected service period. The fair value of the Subsequent Incentive Units will be remeasured on a quarterly basis until all payments have been made. No payments will ever be made by us related to these incentive units; however, non-cash compensation expense will be allocated to us in future periods offset by capital contributions. As such, these awards are not dilutive to our stockholders.

The fair value of the incentive units was estimated using a Monte Carlo simulation valuation model with the following assumptions:

	Exchanged Incentive Units	Subsequent Incentive Units
Valuation date	9/30/2014	9/30/2014
Dividend yield	0%	0%
Expected volatility	21.47%	21.47%
Risk-free rate	0.90%	0.90%
Expected life (years)	2.67	2.67

Note 13. Related Party Transactions

Amounts due to (due from) MRD Holdco and certain affiliates of NGP at September 30, 2014 and December 31, 2013 are presented as Accounts receivable affiliates and Accounts payable affiliates in the accompanying balance sheets.

NGPCIF NPI Acquisition

WildHorse Resources purchased a net profits interest from NGPCIF on February 28, 2014 for a purchase price of $63.4 million (see Note 1). This acquisition was accounted for as a combination of entities under common control at historical cost in a manner similar to the pooling of interest method. WildHorse Resources recorded the following net assets (in thousands):

Accounts receivable	$ 2,274
Oil and natural gas properties, net	40,056
Accrued liabilities	(297)
Asset retirement obligations	(277)
Net assets	$ 41,756

Due to common control considerations, the difference between the purchase price and the net assets acquired are reflected within equity as a deemed distribution to NGP affiliates.

Common Control Transactions between MEMP and Other MRD LLC Subsidiaries

MEMP acquired all of the outstanding membership interests in WHT from WildHorse Resources and Tanos on March 28, 2013 for a purchase price of approximately $200.0 million. On April 1, 2014, MEMP acquired certain oil and natural gas producing properties in East Texas from WildHorse Resources for approximately $33.3 million, including estimated customary post-closing adjustments.

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MEMP acquired of all the outstanding membership interests in Tanos for a purchase price of approximately $77.4 million on October 1, 2013.

MEMP acquired of all the outstanding membership interests in Prospect from Black Diamond for a purchase price of approximately $16.3 million on October 1, 2013.

MEMP acquired of certain of the oil and natural gas properties in Jackson County, Texas from MRD LLC for a purchase price of approximately $2.6 million on October 1, 2013.

Other Acquisitions or Dispositions

On March 10, 2014, BlueStone sold certain interests in oil and gas properties in McMullen, Webb, Zapata, and Hidalgo Counties located in South Texas to BlueStone Natural Resources II, LLC, an NGP controlled entity. Total cash consideration received by BlueStone was approximately $1.2 million, which exceeded the net book value of the properties sold by $0.5 million. Due to common control considerations, the $0.5 million was recognized in the equity statement as a contribution.

On March 28, 2014, MRD Royalty acquired certain interests in oil and gas properties in Gonzales and Karnes Counties located in South Texas from Propel Energy for $3.3 million. Due to common control considerations, this transaction was recognized in the equity statement.

On June 18, 2014, in connection with our initial public offering and the related restructuring transactions (see Note 1), WHR Management Company was sold by WildHorse Resources to an affiliate of the Funds for net book value. The net book value of the assets sold was as follows (in thousands):

Cash and cash equivalents	$ 33,001
Restricted cash	300
Accounts receivable	5,256
Prepaid expenses and other current assets	379
Property, plant and equipment, net	3,410
Other long-term assets	4
Accounts payable	(19,959)
Accounts payable affiliates	(17,099)
Accrued liabilities	(5,061)
Net assets	$ 231

Related Party Agreements

We and certain of our affiliates have entered into various documents and agreements. These agreements have been negotiated among affiliated parties and, consequently, are not the result of arm s-length negotiations.

Registration Rights Agreement

In connection with the closing of our initial public offering, we entered into a registration rights agreement with MRD Holdco and former management members of WildHorse Resources, Jay Graham (Graham) and Anthony Bahr (Bahr). Pursuant to the registration rights agreement, we have agreed to register the sale of shares of our common stock under certain circumstances.

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Voting Agreement

In connection with the closing of our initial public offering, we entered into a voting agreement with MRD Holdco, WHR Incentive LLC, a limited liability company beneficially owned by Messrs. Bahr and Graham, and certain former management members of WildHorse Resources, who contributed their ownership of WildHorse Resources to us in the restructuring transactions. Among other things, the voting agreement provides that those former management members of WildHorse Resources will vote all of their shares of our common stock as directed by MRD Holdco. The voting agreement also prohibits the transfer of any shares of our common stock by the former management members of WildHorse Resources until after the termination of the services agreement described below; provided, however, that the former management members of WildHorse Resources (other than Messrs. Bahr and Graham) may transfer their shares of our common stock after the 180 day lock-up period has expired and these transfer restrictions will not prohibit Messrs. Bahr and Graham from exercising piggyback registration rights under the registration rights agreement described above.

Omnibus Agreement

On December 14, 2011, in connection with the closing of MEMP s initial public offering, MRD LLC entered into an omnibus agreement with MEMP and its general partner. We succeeded to all of MRD LLC s duties and obligations under the omnibus agreement.

Pursuant to the omnibus agreement, MEMP is required to reimburse us for all expenses incurred by us (or payments made on MEMP s behalf) in conjunction with our provision of general and administrative services to MEMP, including, but not limited to, public company expenses and an allocated portion of the salary and benefits of the executive officers of MEMP s general partner and our other employees who perform services for MEMP or on MEMP s behalf. MEMP is also obligated to reimburse us for insurance coverage expenses we incur with respect to MEMP s business and operations and with respect to director and officer liability coverage for the officers and directors of MEMP s general partner.

Beta Management Agreement

On December 12, 2012, MRD LLC entered into a management agreement with its wholly-owned subsidiary, Beta Operating Company, LLC pursuant to which MRD LLC agreed to provide management and administrative oversight with respect to the services provided by such subsidiary under certain operating agreements with a subsidiary of MEMP, in exchange for an annual management fee. We succeeded to this management agreement and we will receive approximately $0.4 million from MEMP annually under that agreement.

Services Agreement

In connection with the closing of our initial public offering, we entered into a services agreement with WildHorse Resources and WHR Management Company, pursuant to which WHR Management Company will provide operating and administrative services to us for twelve months relating to the Terryville Complex. In exchange for such services, we will pay a monthly management fee to WHR Management Company of approximately $1.0 million excluding third party COPAS income credits.

WHR Management Company may only terminate the services agreement by providing 90-days prior written notice to us after the six-month anniversary of the date of the agreement. We may terminate the services agreement at any time by providing written notice to WHR Management Company. The services agreement may only be assigned by either party with the other party s consent. Upon the closing of our initial public offering,

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WHR Management Company became a subsidiary of WildHorse Resources II, LLC, an affiliate of the Company. NGP and certain former management members of WildHorse Resources own WildHorse Resources II, LLC.

Gas Processing Agreement

On March 17, 2014, WildHorse Resources entered into a gas processing agreement with PennTex North Louisiana, LLC (PennTex). PennTex is a joint venture among certain affiliates of NGP in which MRD Holdco, through its subsidiary MRD Midstream LLC, owns a minority interest. Once PennTex s processing plant becomes operational, it will process natural gas produced from wells located on certain leases owned by WildHorse Resources in the state of Louisiana. The agreement has a 15-year primary term, subject to one-year extensions at either party s election. WildHorse Resources will pay PennTex a monthly fee, subject to an annual inflationary escalation, based on volumes of natural gas delivered and processed. Once the plant is declared operational, WildHorse Resources will be obligated to pay a minimum processing fee equal to approximately $18.3 million on an annual basis, subject to certain adjustments and conditions. The gas processing agreement requires that the processing plant be operational no later than November 1, 2015.

Classic Pipeline Gas Gathering Agreement & Water Disposal Agreement

On November 1, 2011, Classic Hydrocarbons Operating, LLC (Classic Operating), which became our wholly-owned subsidiary in connection with the restructuring transactions, and Classic Pipeline entered into a gas gathering agreement. Pursuant to the gas gathering agreement, Classic Operating dedicated to Classic Pipeline all of the natural gas produced (up to 50,000 MMBtus per day) on the properties operated by Classic Operating within certain counties in Texas through 2020, subject to one-year extensions at either party s election. On May 1, 2014, Classic Operating and Classic Pipeline amended the gas gathering agreement with respect to Classic Operating s remaining assets located in Panola and Shelby Counties, Texas. Under the amended gas gathering agreement, Classic Operating agreed to pay a fee of (i) $0.30 per MMBtu, subject to an annual 3.5% inflationary escalation, based on volumes of natural gas delivered and processed, and (ii) $0.07 per MMBtu per stage of compression plus its allocated share of compressor fuel. The amended gas gathering agreement has a term until December 31, 2023, subject to one-year extensions at either party s election.

On May 1, 2014, Classic Operating and Classic Pipeline entered into a water disposal agreement. The water disposal agreement has a three-year term, subject to one-year extensions at either party s election. Under the water disposal agreement, Classic Operating agreed to pay a fee of $1.10 per barrel for each barrel of water delivered to Classic Pipeline.

Note 14. Business Segment Data

Our reportable business segments are organized in a manner that reflects how management manages those business activities.

We have two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties. Our reportable business segments are as follows:

MRD reflects the combined operations of the Company, MRD LLC, WildHorse Resources and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.

MEMP reflects the combined operations of MEMP, its previous owners, and historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

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We evaluate segment performance based on Adjusted EBITDA. Adjusted EBITDA is defined as net income (loss), plus interest expense; loss on extinguishment of debt; income tax expense; depreciation, depletion and amortization (DD&A); impairment of goodwill and long-lived properties; accretion of asset retirement obligations (AROs); losses on commodity derivative contracts and cash settlements received; losses on sale of properties; incentive-based compensation expenses; exploration costs; provision for environmental remediation; equity loss from MEMP (MRD Segment only); cash distributions from MEMP (MRD Segment only); acquisition related costs; amortization of investment premium; and other non-routine items, less interest income; income tax benefit; gains on commodity derivative contracts and cash settlements paid; equity income from MEMP (MRD Segment only); gains on sale of assets and other non-routine items.

Financial information presented for the MEMP business segment is derived from the underlying consolidated and combined financial statements of MEMP that are publicly available.

Segment revenues and expenses include intersegment transactions. Our combined totals reflect the elimination of intersegment transactions.

In the MRD Segment s individual financial statements, investments in the MEMP Segment that are included in the consolidated and combined financial statements are accounted for by the equity method.

The following table presents selected business segment information for the periods indicated (in thousands):

	MRD	MEMP	Other, Adjustments & Eliminations	Consolidated & Combined Totals
Total revenues:				
Nine months ended September 30, 2014	$ 301,492	$ 371,530	$ (137)	$ 672,885
Nine months ended September 30, 2013	171,361	251,516	(136)	422,741
Adjusted EBITDA: (1)				
Nine months ended September 30, 2014	247,335	218,842	(18,912)	447,265
Nine months ended September 30, 2013	153,679	157,160	(19,554)	291,285
Segment assets: (2)				
As of September 30, 2014	1,232,146	2,749,452	40,069	4,021,667
As of December 31, 2013	1,281,134	1,552,307	(4,280)	2,829,161
Total cash expenditures for additions to long-lived assets:				
Nine months ended September 30, 2014	(276,982)	(1,273,157)		(1,550,139)
Nine months ended September 30, 2013	(198,220)	(165,403)		(363,623)

(1) Adjustments and eliminations for the nine months ended September 30, 2014 and 2013 include amounts related to the MRD s Segment equity investments in the MEMP Segment as well as the elimination of $6.1 million of cash distributions that MEMP paid MRD for the nine months ended September 30, 2014, and $19.1 million of cash distributions that MEMP paid MRD LLC for the nine months ended September 30, 2013, related to MRD LLC s partnership interests in MEMP.

(2) Adjustments and eliminations primarily represent the elimination of the MRD s Segment equity investments in the MEMP Segment. The adjustment at September 30, 2014 and December 31, 2013 also includes $47.3 million and $49.9 million, respectively related to an impairment recognized by the MEMP Segment during 2013. This impairment did not exist on a consolidated basis.

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Calculation of Reportable Segments Adjusted EBITDA

	For the Nine Months Ended September 30, 2014		
	MRD	MEMP (In thousands)	Combined Totals
Net income (loss)	$ (930,149)	$ (45,037)	$ (975,186)
Interest expense, net	44,355	60,573	104,928
Loss on extinguishment of debt	37,248		37,248
Income tax expense (benefit)	14,323	75	14,398
DD&A	107,496	105,830	213,326
Impairment of proved oil and natural gas properties		67,181	67,181
Accretion of AROs	495	4,106	4,601
(Gain) loss on commodity derivative instruments	(17,130)	28,710	11,580
Cash settlements received (paid) on commodity derivative instruments	(4,930)	(14,999)	(19,929)
(Gain) loss on sale of properties	3,057		3,057
Acquisition related costs	1,568	3,912	5,480
Incentive-based compensation expense	970,877	5,387	976,264
Exploration costs	1,213	252	1,465
Provision for environmental remediation		2,852	2,852
Non-cash equity (income) loss from MEMP	12,844		12,844
Cash distributions from MEMP	6,068		6,068
Adjusted EBITDA	$ 247,335	$ 218,842	$ 466,177

	For the Nine Months Ended September 30, 2013		
	MRD	MEMP (In thousands)	Combined Totals
Net income (loss)	$ 114,628	$ 9,359	$ 123,987
Interest expense, net	15,947	26,047	41,994
Income tax expense (benefit)	1,147	285	1,432
DD&A	62,605	69,723	132,328
Impairment of proved oil and natural gas properties		50,310	50,310
Accretion of AROs	547	3,469	4,016
(Gain) loss on commodity derivative instruments	(8,361)	(21,195)	(29,556)
Cash settlements received (paid) on commodity derivative instruments	9,125	14,081	23,206
(Gain) loss on sale of properties	(83,370)	(2,848)	(86,218)
Acquisition related costs	1,651	3,422	5,073
Incentive-based compensation expense	19,069	2,322	21,391
Non-cash compensation expense		1,057	1,057
Exploration costs	1,137	1,128	2,265
Non-cash equity (income) loss from MEMP	454		454
Cash distributions from MEMP	19,100		19,100

Adjusted EBITDA	$ 153,679	$ 157,160	$ 310,839

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The following table presents a reconciliation of total reportable segments Adjusted EBITDA to net income (loss) for each of the periods indicated (in thousands).

	For the Nine Months Ended September 30,	
	2014	**2013**
Total Reportable Segments Adjusted EBITDA	$ 466,177	$ 310,839
Adjustments to reconcile Adjusted EBITDA to net income (loss):		
Interest expense, net	(104,928)	(41,994)
Loss on extinguishment of debt	(37,248)	
Income tax benefit (expense)	(14,398)	(1,432)
DD&A	(215,906)	(132,328)
Impairment of proved oil and natural gas properties	(67,181)	(21)
Accretion of AROs	(4,601)	(4,016)
Gains (losses) on commodity derivative instruments	(11,580)	29,556
Cash settlements paid (received) on commodity derivative instruments	19,929	(23,206)
Gain (loss) on sale of properties	(3,057)	86,218
Acquisition related costs	(5,480)	(5,073)
Incentive-based compensation expense)	(976,264)	(21,391)
Non-cash compensation expense		(1,057)
Exploration costs	(1,465)	(2,265)
Provision for environmental remediation	(2,852)	
Cash distributions from MEMP	(6,068)	(19,100)
Other non-cash equity (income) loss		(430)
Net income (loss)	$ (964,922)	$ 174,300

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Included below is our consolidated and combined statement of operations disaggregated by reportable segment for the period indicated (in thousands):

	For the Nine Months Ended September 30, 2014			
	MRD	MEMP	Other, Adjustments & Eliminations	Consolidated & Combined Totals
Revenues:				
Oil & natural gas sales	$ 300,931	$ 368,370	$	$ 669,301
Other revenues	561	3,160	(137)	3,584
Total revenues	301,492	371,530	(137)	672,885
Costs and expenses:				
Lease operating	18,657	93,367	(137)	111,887
Pipeline operating		1,596		1,596
Exploration	1,213	252		1,465
Production and ad valorem taxes	10,494	23,129		33,623
Depreciation, depletion, and amortization	107,496	105,830	2,580	215,906
Impairment of proved oil and natural gas properties		67,181		67,181
Incentive unit compensation expense	969,390			969,390
General and administrative	29,301	31,760		61,061
Accretion of asset retirement obligations	495	4,106		4,601
(Gain) loss on commodity derivative instruments	(17,130)	28,710		11,580
(Gain) loss on sale of properties	3,057			3,057
Other, net		(12)		(12)
Total costs and expenses	1,122,973	355,919	2,443	1,481,335
Operating income (loss)	(821,481)	15,611	(2,580)	(808,450)
Other income (expense):				
Interest expense, net	(44,355)	(60,573)		(104,928)
Loss on extinguishment of debt	(37,248)			(37,248)
Earnings from equity investments	(12,844)		12,844	
Other, net	102			102
Total other income (expense)	(94,345)	(60,573)	12,844	(142,074)
Income (loss) before income taxes	(915,826)	(44,962)	10,264	(950,524)
Income tax benefit (expense)	(14,323)	(75)		(14,398)
Net income (loss)	$ (930,149)	$ (45,037)	$ 10,264	$ (964,922)

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	For the Nine Months Ended September 30, 2013			
	MRD	MEMP	Other, Adjustments & Eliminations	Consolidated & Combined Totals
Revenues:				
Oil & natural gas sales	$ 171,013	$ 249,844	$	$ 420,857
Other revenues	348	1,672	(136)	1,884
Total revenues	171,361	251,516	(136)	422,741
Costs and expenses:				
Lease operating	17,065	64,922	(241)	81,746
Pipeline operating		1,343		1,343
Exploration	1,137	1,128		2,265
Production and ad valorem taxes	8,563	14,915		23,478
Depreciation, depletion, and amortization	62,605	69,723		132,328
Impairment of proved oil and natural gas properties		50,310	(50,289)	21
Incentive unit compensation expense	19,069			19,069
General and administrative	22,466	33,411	105	55,982
Accretion of asset retirement obligations	547	3,469		4,016
(Gain) loss on commodity derivative instruments	(8,361)	(21,195)		(29,556)
(Gain) loss on sale of properties	(83,370)	(2,848)		(86,218)
Other, net	(25)	647		622
Total costs and expenses	39,696	215,825	(50,425)	205,096
Operating income (loss)	131,665	35,691	50,289	217,645
Other income (expense):				
Interest expense, net	(15,947)	(26,047)		(41,994)
Earnings from equity investments	(24)		24	
Other, net	81			81
Total other income (expense)	(15,890)	(26,047)	24	(41,913)
Income before income taxes	115,775	9,644	50,313	175,732
Income tax benefit (expense)	(1,147)	(285)		(1,432)
Net income (loss)	$ 114,628	$ 9,359	$ 50,313	$ 174,300

Note 15. Commitments and Contingencies

Litigation & Environmental

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our financial position, results of operations or cash flows.

At September 30, 2014 and December 31, 2013, we had $2.3 million and $0.6 million of environmental reserves recorded on our balance sheets, respectively. During the nine months ended September 30, 2014, MEMP

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recorded $2.9 million of estimated environmental remediation expenses associated with its Permian and Wyoming oil and gas properties. These expenses are reflected as a component of lease operating expenses on our statement of operations. Environmental costs for remediation are accrued when environmental remediation efforts are probable and the costs can be reasonably estimated. Such accruals are based on management s best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals.

Supplemental Bond for Decommissioning Liabilities Trust Agreement

The trust account is held by Rise Energy Operating, LLC (REO), a wholly-owned subsidiary of MEMP, for the benefit of all working interest owners. The following is a summary of the gross held-to-maturity investments held in the trust account less the outside working interest owners share as of September 30, 2014 (in thousands):

Investment	**Amortized Cost**
U.S. Bank Money Market Cash Equivalent	$ 133,275
Less: Outside working interest owners share	(64,305)
	$ 68,970

The trust account must maintain minimum balances attributable to REO s net working interest as follows (in thousands):

June 30, 2015	$ 72,450
June 30, 2016	$ 76,590
December 31, 2016	$ 78,660

As of September 30, 2014, the maximum remaining obligation net to REO s interest was approximately $9.7 million.

Purchase Commitment Assumed

At September 30, 2014, MEMP had a CO_2 purchase commitment with a third party that was assumed in its Wyoming Acquisition. The table below outlines MEMP s purchase commitment under the contract for the remainder of 2014 and annually thereafter (in thousands):

	Payment or Settlement due by Period						
Purchase commitment	**Total**	**Remainder 2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**
CO_2 minimum purchase commitment:							
Estimated payment obligation	$ 62,103	$ 3,203	$ 12,222	$ 12,101	$ 11,624	$ 7,872	$ 15,081

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Processing Plant Expansions by Third Party Gatherer

In 2012, WildHorse Resources contracted with Regency Field Services LLC (the Gatherer) to expand their Dubach processing plant by up to 70 MMcf per day among other facility and infrastructure improvements. The expansion project was complete and fully operational by July 2013. WildHorse Resources will pay a payback demand fee until the payback demand fees received by the Gatherer plus any third party fees equal 110% of the new facility cost. For each month from the commencement date through the month in which the payout date occurs, WildHorse Resources will pay a payback demand fee equal to the monthly demand quantity (136,200 MMBtu per day) times $0.26 per MMBtu. In addition, for each MMBtu gathered in excess of the demand quantity, WildHorse Resources will pay a payback demand fee of $0.26 per MMBtu. The contract with the Gatherer for the Dubach processing plant was amended effective February 1, 2014 where the payback demand fee for the Dubach processing plant increased from $0.26 to $0.275 cents per MMbtu.

In 2013, WildHorse Resources contracted with the Gatherer to build a new high pressure pipeline from the dedicated area to the Gatherer s Dubberly processing plant in Webster Parish, LA amongst other pipeline and infrastructure improvements. The expansion project was complete and fully operational by mid-December 2013. WildHorse Resources will pay a payback demand fee until the payback demand fees received by the Gatherer plus any third party fees equal to 110% of the pipeline and infrastructure improvement costs. For each month from the commencement date through the month in which the payout date occurs, WildHorse Resources will pay a payback demand fee equal to the monthly demand fee times $0.31 per MMBtu. In addition, for each MMBtu gathered in excess of the demand quantity, WildHorse Resources will pay a payback demand fee of $0.31 per MMBtu. The monthly demand quantity is 56,750 MMBtu per day from the Dubberly start-up date through one full year thereafter and then increasing to 113,500 MMBtu per day until payout. The contract with the Gatherer for the new high pressure pipeline was amended effective February 1, 2014 where the payback demand fee decreased from $0.31 to $0.275 cents per MMbtu.

WildHorse Resources minimum commitments to the Gatherer, before other owner contributions, as of September 30, 2014 were as follows (in thousands):

	Dubach	Dubberly
2014	$ 3,446	$ 1,436
2015	13,671	11,393
2016	13,709	11,424
2017	13,671	11,393
2018	12,772	10,643
Total	$ 57,269	$ 46,289

Related Party Agreements

On March 17, 2014, WildHorse Resources entered into a gas processing agreement with PennTex. See Note 13 for additional information.

Classic Operating entered into a gas gathering agreement and water disposal agreement with Classic Pipeline. See Note 13 for additional information.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Note 16. Subsequent Events

Common Control Transaction

On October 1, 2014, MRD sold certain oil and natural gas properties in Colorado to MEMP for a purchase price of $15 million, subject to customary post-closing adjustments. The properties are located in Weld County, Colorado in the Wattenberg Field. The properties are 100% non-operated and included interests in 74 gross wells. The transaction had an effective date of October 1, 2014 and was funded with borrowings under MEMP s revolving credit facility. The transaction was approved by our Board and its audit committee, which is comprised entirely of independent directors.

MRD Revolving Credit Facility

On October 3, 2014, the borrowing base under our credit facility was increased. For additional information regarding MRD s revolving credit facility, see Note 8.

MEMP Revolving Credit Facility

On October 10, 2014, the borrowing base under the MEMP credit facility was redetermined and increased. For additional information regarding MEMP s revolving credit facility, see Note 8.

Terryville Mineral & Royalty Partners LP

On November 4, 2014, the Company s wholly-owned subsidiary, Terryville Mineral & Royalty Partners LP (TRVL), filed a registration statement on Form S-1 with the SEC in connection with its proposed initial public offering of common units representing limited partner interests. In connection with the closing of the proposed offering, the Company will contribute to TRVL certain overriding royalty interests in approximately 27,000 gross acres in the Terryville Complex in exchange for limited partner interests in TRVL. The royalty interests will entitle TRVL to receive 7% of gross revenues from production within such acreage on all of the Company s existing horizontal producing wells and future wells completed by the Company. TRVL intends to distribute the net proceeds from the proposed offering to the Company. A registration statement relating to these securities has been filed with the SEC but has not yet become effective. These securities may not be sold nor may any offers to buy be accepted prior to the time the registration statement becomes effective, and this prospectus does not constitute an offer to sell or a solicitation of any offers to buy these securities.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Managers

Memorial Resource Development LLC:

We have audited the accompanying consolidated and combined balance sheets of Memorial Resource Development LLC and subsidiaries (the Company) as of December 31, 2013 and 2012, and the related consolidated and combined statements of operations, equity, and cash flows for the years then ended. In connection with our audits of the consolidated and combined financial statements, we also have audited Schedule I Condensed Financial Information (Schedule I). These consolidated and combined financial statements and Schedule I are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated and combined financial statements and Schedule I based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated and combined financial statements referred to above present fairly, in all material respects, the financial position of Memorial Resource Development LLC and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years then ended in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related Schedule I, when considered in relation to the basic consolidated and combined financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated and combined financial statements, the balances sheets, and the related statements of operations, equity, and cash flows have been prepared on a combined basis of accounting.

/s/ KPMG LLP

Dallas, Texas

April 4, 2014

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

CONSOLIDATED AND COMBINED BALANCE SHEETS

(In thousands)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 77,721	$ 49,391
Restricted cash	35,000	2,013
Accounts receivable:		
Oil and natural gas sales	68,764	64,128
Joint interest owners and other	19,958	17,701
Affiliates	4,652	77
Short-term derivative instruments	9,289	41,921
Prepaid expenses and other current assets	19,513	13,577
Total current assets	234,897	188,808
Property and equipment, at cost:		
Oil and natural gas properties, successful efforts method	3,037,298	2,637,466
Other	10,331	9,920
Accumulated depreciation, depletion and impairment	(627,925)	(471,949)
Oil and natural gas properties, net	2,419,704	2,175,437
Long-term derivative instruments	48,616	17,179
Restricted investments	73,385	68,024
Restricted cash	15,506	
Other long-term assets	37,053	9,856
Total assets	$ 2,829,161	$ 2,459,304
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 20,734	$ 36,633
Accounts payable affiliates	1,975	
Revenues payable	56,091	50,967
Accrued liabilities	98,130	33,487
Short-term derivative instruments	9,711	4,667
Total current liabilities	186,641	125,754
Long-term debt MRD Segment	871,150	309,200
Long-term debt MEMP Segment	792,067	630,182
Asset retirement obligations	111,679	101,990
Long-term derivative instruments	6,080	11,623
Other long-term liabilities	3,412	3,846
Total liabilities	1,971,029	1,182,595
Commitments and contingencies (Note 14)		
Equity:		
Members	237,186	811,614
Previous owners (Note 1)	40,331	233,433

Total members equity	277,517	1,045,047
Noncontrolling interest	580,615	231,662
Total equity	858,132	1,276,709
Total liabilities and equity	$ 2,829,161	$ 2,459,304

See Accompanying Notes to Consolidated and Combined Financial Statements.

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

STATEMENTS OF CONSOLIDATED AND COMBINED OPERATIONS

(In thousands)

	For Year Ended December 31, 2013	2012
Revenues:		
Oil & natural gas sales	$ 571,948	$ 393,631
Other revenues	3,075	3,237
Total revenues	575,023	396,868
Costs and expenses:		
Lease operating	113,640	103,754
Pipeline operating	1,835	2,114
Exploration	2,356	9,800
Production and ad valorem taxes	27,146	23,624
Depreciation, depletion, and amortization	184,717	138,672
Impairment of proved oil and natural gas properties	6,600	28,871
General and administrative	125,358	69,187
Accretion of asset retirement obligations	5,581	5,009
(Gain) loss on commodity derivative instruments	(29,294)	(34,905)
(Gain) loss on sale of properties	(85,621)	(9,761)
Other, net	649	502
Total costs and expenses	352,967	336,867
Operating income	222,056	60,001
Other income (expense):		
Interest expense, net	(69,250)	(33,238)
Amortization of investment premium		(194)
Other, net	145	535
Total other income (expense)	(69,105)	(32,897)
Income before income taxes	152,951	27,104
Income tax benefit (expense)	(1,619)	(107)
Net income	151,332	26,997
Net income (loss) attributable to noncontrolling interest	49,830	(2,701)
Net income (loss) attributable to Memorial Resource Development LLC	$ 101,502	$ 29,698
Net income (loss) attributable to members	$ 90,712	$ (7,620)
Net income (loss) attributable to previous owners (Note 1)	10,790	37,318
Net income (loss) attributable to Memorial Resource Development LLC	$ 101,502	$ 29,698

Income before income taxes	152,951	27,104
Pro forma provision for income taxes (Note 2)	(55,154)	(9,592)
Pro forma net income	$ 97,797	$ 17,512
Pro forma basic earnings per share (Note 2)	$ 0.31	$ (0.03)
Pro forma diluted earnings per share (Note 2)	$ 0.30	$ (0.03)
Pro forma basic weighted average shares outstanding	192,500	192,500
Pro forma diluted weighted average shares outstanding	193,676	193,676

See Accompanying Notes to Consolidated and Combined Financial Statements.

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

STATEMENTS OF CONSOLIDATED AND COMBINED CASH FLOWS

(In Thousands)

	For Year Ended December 31, 2013	2012
Cash flows from operating activities:		
Net income	$ 151,332	$ 26,997
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	184,717	138,672
Impairment of oil and natural gas properties	6,600	28,871
(Gain) loss on derivative instruments	(29,533)	(29,323)
Cash settlements on derivative instruments	30,403	72,045
Premiums paid for derivatives		(411)
Deferred income tax expense (benefit)	76	(312)
Amortization of loan origination costs	8,343	3,584
Accretion of senior notes net discount	554	
Amortization of investment premium		194
Accretion of asset retirement obligations	5,581	5,009
Amortization of MEMP equity awards	3,557	1,423
(Gain) loss on sale of properties	(85,621)	(9,761)
Non-cash compensation expense	1,057	
Exploration costs	181	6,980
Changes in operating assets and liabilities:		
Accounts receivable	(15,758)	(7,382)
Prepaid expenses and other	(2,986)	(1,574)
Payables and accrued liabilities	19,320	5,392
Net cash provided by operating activities	277,823	240,404
Cash flows from investing activities:		
Acquisition of oil and natural gas properties	(105,762)	(360,678)
Additions to oil and gas properties	(360,015)	(273,334)
Additions to restricted investments	(5,361)	(4,599)
Additions to other property and equipment	(2,670)	(2,674)
Additions to restricted cash	(49,347)	(3)
Proceeds from the sale of oil and gas properties	155,712	34,521
Other		29
Net cash used in investing activities	(367,443)	(606,738)
Cash flows from financing activities:		
Advances on revolving credit facility	1,132,755	619,450
Payments on revolving credit facility	(1,766,037)	(251,569)
Loan origination fees	(41,175)	(3,501)
Borrowings under second lien credit facility	325,000	
Proceeds from the issuances of senior notes	1,031,563	
Purchase of additional interests in consolidated subsidiaries	(15,135)	
Contributions from previous owners	1,214	44,072
Proceeds from changes in ownership interests of MEMP	135,012	
Proceeds from MEMP public equity offering	511,204	202,573
Costs incurred in conjunction with MEMP public equity offering	(21,066)	(8,268)
Contributions from NGP affiliates related to sale of properties	2,013	45,158
Distributions to the Funds	(732,362)	
Distributions to noncontrolling interests	(78,083)	(15,208)
Distribution to NGP affiliates (see Note 1)	(355,494)	(242,174)
Distributions made by previous owners	(4,005)	(28,772)

Cash retained by previous owners	(7,909)	
Other	455	
Net cash provided by financing activities	117,950	361,761
Net change in cash and cash equivalents	28,330	(4,573)
Cash and cash equivalents, beginning of year	49,391	53,964
Cash and cash equivalents, end of year	$ 77,721	$ 49,391
Supplemental cash flows:		
Cash paid for interest	$ 61,140	$ 23,525
Noncash investing and financing activities:		
Change in capital expenditures in payables and accrued liabilities	41,017	17,158
Assumptions of asset retirement obligations related to properties acquired or drilled	4,227	7,962
Contribution of oil and gas properties from NGP affiliate		6,893
Accrued distribution to NGP affiliates related to Cinco Group acquisition	4,352	
Contribution related to sale of assets to NGP affiliate restricted cash		2,013
Accrued equity offering costs		171
Distributions to noncontrolling interests		47

See Accompanying Notes to Consolidated and Combined Financial Statements.

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

STATEMENTS OF CONSOLIDATED AND COMBINED EQUITY

(In Thousands)

	Members	Members Equity Previous Owner	Noncontrolling Interest	Total
Balance January 1, 2012	$ 853,436	$ 261,340	$ 161,588	$ 1,276,364
Net income (loss)	(7,620)	37,318	(2,701)	26,997
Contributions		44,072		44,072
Contribution of oil and gas properties from NGP affiliate		6,893		6,893
Net proceeds from MEMP public equity offering			194,134	194,134
Distributions		(28,772)	(15,255)	(44,027)
Net book value of net assets acquired from affiliates (Note 12)	52,217	(93,696)	41,479	
Amortization of MEMP equity awards			1,423	1,423
Noncontrolling interest s share of net book value in excess of consideration received from sale of assets to MEMP	727		(727)	
Contribution related to sale of assets to NGP affiliate	6,291	40,138	742	47,171
Net book value of assets acquired by NGP affiliate	(579)	(33,859)	(68)	(34,506)
Distribution to affiliate in connection with acquisition of assets	(134,964)		(107,210)	(242,174)
Impact from equity transactions of MEMP	41,930		(41,930)	
Other	176	(1)	187	362
Balance December 31, 2012	811,614	233,433	231,662	1,276,709
Net income (loss)	90,712	10,790	49,830	151,332
Contributions		1,214		1,214
Net proceeds from MEMP public equity offering			490,138	490,138
Sale of MEMP common units	60,701		74,311	135,012
Distributions	(732,362)	(4,005)	(78,083)	(814,450)
Net book value of net assets acquired from affiliates (Note 12)	50,751	(181,556)	130,805	
Amortization of MEMP equity awards			3,557	3,557
Noncontrolling interest s share of cash consideration received in excess of the net book value sold to MEMP	(24)		24	
Distribution to affiliate in connection with acquisition of assets	(98,180)		(253,055)	(351,235)
Purchase of noncontrolling interests	(303)		(14,832)	(15,135)
Impact from equity transactions of MEMP	54,183		(54,183)	
Other	94	(2,299)	441	(1,764)
Net assets retained by previous owners		(17,246)		(17,246)
Balance December 31, 2013	237,186	40,331	580,615	858,132

See Accompanying Notes Consolidated and Combined Financial Statements.

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Note 1. Background, Organization and Basis of Presentation

Background & Organization

Memorial Resource Development LLC (Memorial Resource) is a Delaware limited liability company (the Company) formed on April 27, 2011 by Natural Gas Partners VIII, L.P. (NGP VIII), Natural Gas Partners IX, L.P. (NGP IX) and NGP IX Offshore Holdings, L.P. (NGP IX Offshore) (collectively, the Funds) to own, acquire, exploit and develop oil and natural gas properties. The Funds are private equity funds managed by Natural Gas Partners (NGP). Unless the context requires otherwise, references to we, us, our, or the Company are intended to m the business and operations of Memorial Resource Development LLC and its consolidated subsidiaries.

These financial statements have been prepared in anticipation of a proposed initial public offering (the Offering) of the common stock of Memorial Resource Development Corp. (MRDC). In connection with the closing of the Offering, Memorial Resource will contribute its ownership interests in all of its directly owned subsidiaries except for BlueStone Natural Resources Holdings, LLC (BlueStone Holdings), Golden Energy Partners LLC (Golden Energy) and Classic Pipeline & Gathering, LLC (Classic Pipeline) as well as two immaterial subsidiaries that were recently formed, and 50% of the incentive distribution rights of Memorial Production Partners LP (MEMP) in exchange for shares of common stock of MRDC. MRDC will become a subsidiary of Memorial Resource. Memorial Resource s consolidated and combined financial statements represent MRDC s predecessor for accounting and financial reporting purposes.

At December 31, 2013, BlueStone Holdings total assets were less than 1% of consolidated total assets and the MRD Segment s total assets. BlueStone Holdings total revenues were approximately 3% of consolidated total revenues and 7% of the MRD Segment s total revenues for the year ended December 31, 2013. BlueStone Holdings production volumes were approximately 2% of consolidated production volumes and 4% of the MRD Segment s production volumes for the year ended December 31, 2013.

As of December 31, 2013, Memorial Resource s significant consolidating subsidiaries consisted of the following:

Memorial Production Partners GP LLC (MEMP GP), a wholly-owned subsidiary, owns a 0.1% general partner interest in MEMP represented by 61,300 general partner units as of December 31, 2013. MEMP is a publicly traded Delaware limited partnership, the common units of which are listed on the NASDAQ Global Market under the symbol MEMP. MEMP was formed in April 2011 to own and acquire oil and natural gas properties in North America and completed its initial public offering on December 14, 2011. MEMP s business activities are conducted through its wholly-owned subsidiary Memorial Production Operating LLC (OLLC) and its subsidiaries. All of OLLC s consolidating subsidiaries are wholly-owned either directly or indirectly, except for one indirect majority-owned subsidiary. At December 31, 2013, Memorial Resource owned all of the 5,360,912 subordinated units outstanding. The Funds collectively indirectly own 50% of MEMP s incentive distribution rights (IDRs). Memorial Resource owns the remaining IDRs. MEMP s assets consist primarily of producing oil and natural gas properties and are located in Texas, Louisiana, Colorado, Wyoming, New Mexico, and offshore Southern California.

Black Diamond Minerals, LLC (Black Diamond), a wholly-owned subsidiary, together with its majority-owned subsidiary are engaged in the exploration, development, production, and operations of oil and natural gas properties located in Colorado, Oklahoma, and Wyoming.

BlueStone Holdings, a majority-owned subsidiary, together with its consolidated subsidiaries (collectively, BlueStone) are engaged in the exploration, development, production, and operations of oil and natural gas properties located in Texas. As of December 31, 2013, Memorial Resource owned an

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

89.45% membership interest in BlueStone Holdings and other individuals owned the remaining membership interests. All of BlueStone Holdings consolidating subsidiaries are wholly-owned either directly or indirectly.

Classic Hydrocarbons Holdings, L.P. (Classic), an indirect wholly-owned subsidiary, together with its consolidated subsidiaries are engaged in the exploration, development, production, and sale of oil and natural gas primarily in East Texas and Louisiana. As of December 31, 2013, Classic Hydrocarbons GP CO., L.L.C. (Classic GP) owned a 0.41% general partner interest in Classic and Memorial Resource owned a 99.59% limited partner interest in Classic. All of Classic s consolidating subsidiaries are wholly-owned either directly or indirectly. As of December 31, 2013, Memorial Resource owned a 100% membership interest in Classic GP.

WildHorse Resources, LLC (WildHorse), a majority-owned subsidiary, together with its wholly-owned subsidiary are engaged in the acquisition, exploitation, and development of natural gas and crude oil properties located in Louisiana and Texas. As of December 31, 2013, Memorial Resource owned a 99.89% membership interest in WildHorse and other individuals owned the remaining membership interests. In connection with the closing of the Offering, the remaining membership interests will be contributed to MRDC and incentive units held by certain members of management will be exchanged for shares of common stock of MRDC and cash consideration.

Beta Operating Company, LLC (Beta Operating), a wholly-owned subsidiary, employs those employees who operate and support MEMP s offshore Southern California oil and gas properties. Beta Operating was contributed to Memorial Resource by MEMP in December 2012. This entity was formerly owned by an affiliate of NGP. MEMP s acquisition of Beta Operating in December 2012 and the subsequent contribution to Memorial Resource were accounted for as common control transactions at historical cost.

Memorial Resource Finance Corp. (MRD Finance Corp.), a wholly-owned subsidiary, has no material assets or any liabilities other than as a co-issuer of our debt securities. Its activities will be limited to co-issuing our debt securities and engaging in other activities incidental thereto.

MEMP acquired certain oil and natural gas producing properties in East Texas from Tanos Energy, LLC (Tanos) on April 2, 2012. Prior to April 1, 2013, Memorial Resource owned a 98.94% membership interest in Tanos. On April 1, 2013, Memorial Resource purchased the remaining membership interest in Tanos (see Note 11). MEMP acquired certain oil and natural gas producing properties in East Texas from Classic on May 14, 2012; acquired all of the outstanding membership interests in WHT Energy Partners LLC (WHT) from WildHorse and Tanos on March 28, 2013; acquired all the outstanding membership interests in Prospect Energy, LLC (Prospect Energy) from Black Diamond on October 1, 2013; acquired all of the outstanding membership interests in Tanos from Memorial Resource on October 1, 2013; acquired certain of the oil and natural gas properties in Jackson County, Texas (the MRD Assets) from Memorial Resource on October 1, 2013; and acquired certain oil and natural gas producing properties in East Texas from WildHorse on April 1, 2014. These intercompany transactions have been eliminated in preparation of our consolidated and combined financial statements.

References to previous owners for accounting and financial reporting purposes refer collectively to:

Rise Energy Operating, LLC and its wholly-owned subsidiaries (except for Rise Energy Operating, Inc.) (REO) from February 3, 2009 (inception) through the date of acquisition. MEMP acquired REO, which owns certain operating interests in producing and non-producing oil and gas properties offshore Southern California, in December 2012 from Rise Energy Partners, LP (Rise). Beta Operating was a wholly-owned subsidiary of Rise Energy Operating, LLC until it was contributed to Memorial Resource by MEMP in

December 2012. Rise is primarily owned by two of the Funds.

Certain oil and natural gas properties and related assets primarily in the Permian Basin, East Texas and the Rockies that MEMP acquired through equity transactions on October 1, 2013 from certain affiliates of

MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

NGP. On October 1, 2013, MEMP acquired Boaz Energy, LLC (Boaz), Crown Energy Partners, LLC (Crown), the Crown net profits interest and overriding royalty interest (Crown NPI/ORRI), Propel Energy SPV LLC (Propel SPV), together with its wholly-owned subsidiary Propel Energy Services, LLC (Propel Energy Services), and Stanolind Oil and Gas SPV LLC (Stanolind SPV) from: (a) Boaz Energy Partners, LLC (Boaz Energy Partners), Crown Energy Partners Holdings, LLC (Crown Holdings), Propel Energy, LLC (Propel Energy) and Stanolind Oil and Gas LP (Stanolind), all of which are primarily owned by two of the Funds.

A net profits interest that WildHorse purchased from NGP Income Co-Investment Fund II, L.P. (NGPCIF) on February 28, 2014 (NGPCIF NPI). NGPCIF is controlled by NGP. Upon the completion of the 2010 Petrohawk and Clayton Williams acquisitions, WildHorse sold a net profits interest in these properties to NGPCIF (see Note 12). Since WildHorse sold the net profits interest, the historical results are accounted for as a working interest for all periods.

Basis of Presentation

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest. Likewise, the combined financial statements include those of the previous owners for the periods that those entities were under common control.

All material intercompany transactions and balances have been eliminated in preparation of our consolidated and combined financial statements. The accompanying consolidated and combined financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). In the opinion of management, all adjustments necessary for a fair presentation of the financial statements have been made. Certain amounts in the prior year financial statements have been reclassified to conform to the presentation in the current year financial statements.

We have two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties (See Note 13). Our reportable business segments are as follows:

MRD reflects the combined operations of Memorial Resource, WildHorse and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.

MEMP reflects the combined operations of MEMP, its previous owners, and any dropdown transactions between MEMP and other Memorial Resource subsidiaries.

Segment financial information has been retrospectively revised for the following common control transactions between MEMP and other Memorial Resource subsidiaries for comparability purposes:

acquisition by MEMP of all the outstanding membership interests in Tanos for a purchase price of approximately $77.4 million on October 1, 2013;

acquisition by MEMP of all the outstanding membership interests in Prospect Energy for a purchase price of approximately $16.3 million on October 1, 2013;

acquisition by MEMP of all the outstanding membership interests in WHT for a purchase price of approximately $200.0 million on March 28, 2013;

acquisition by MEMP of certain assets from Classic in East Texas in May 2012 for a purchase price of approximately $27.0 million; and

acquisition by MEMP of certain assets from Tanos in East Texas in April 2012 for a purchase price of approximately $18.5 million.

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

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Note 2. Summary of Significant Accounting Policies

Use of Estimates

The preparation of consolidated and combined financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated and combined financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Significant estimates include, but are not limited to, oil and natural gas reserves; depreciation, depletion, and amortization of proved oil and natural gas properties; future cash flows from oil and natural gas properties; impairment of long-lived assets; fair value of derivatives; fair value of equity compensation; fair values of assets acquired and liabilities assumed in business combinations and asset retirement obligations.

Principles of Consolidation and Combination

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest. Likewise, the combined financial statements include those of the previous owners. All material intercompany balances and transactions have been eliminated.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and all highly liquid investments with original contractual maturities of three months or less.

Concentrations of Credit Risk

Cash balances, accounts receivable, restricted investments and derivative financial instruments are financial instruments potentially subject to credit risk. Cash and cash equivalents are maintained in bank deposit accounts which, at times, may exceed the federally insured limits. Management periodically reviews and assesses the financial condition of the banks to mitigate the risk of loss. Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Southern California oil and gas properties. These restricted investments consist of money market deposit accounts, money market mutual funds, commercial paper, and U.S. Government securities, all held with credit-worthy financial institutions. Derivative financial instruments are generally executed with major financial institutions that expose us to market and credit risks and which may, at times, be concentrated with certain counterparties. The credit worthiness of the counterparties is subject to continual review. We rely upon netting arrangements with counterparties to reduce credit exposure. We have not experienced any losses from such instruments.

Oil and natural gas are sold to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. Accounts receivable from joint operations are from a number of oil and natural gas companies, partnerships, individuals, and others who own interests in the properties operated by us and our predecessor. Generally, operators of crude oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells, minimizing the credit risk associated with these receivables. Additionally, management believes that any credit risk imposed by a concentration in the oil and natural gas industry is mitigated by the creditworthiness of its customer base. An

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

allowance for doubtful accounts is recorded after all reasonable efforts have been exhausted to collect or settle the amount owed. Any amounts outstanding longer than the contractual terms are considered past due. Management determined that an allowance for uncollectible accounts was unnecessary at both December 31, 2013 and 2012, respectively.

If we were to lose any one of our customers, the loss could temporarily delay production and the sale of oil and natural gas in the related producing region. If we were to lose any single customer, we believe that a substitute customer to purchase the impacted production volumes could be identified.

Oil and Natural Gas Properties

Oil and natural gas exploration, development and production activities are accounted for in accordance with the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells, and development costs are capitalized. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete. Exploration costs such as geological, geophysical, and seismic costs are expensed as incurred.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties are subject to depreciation and depletion. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated field. Capitalized drilling and development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves.

On the sale or retirement of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated depreciation, depletion, and amortization are removed from the property accounts, and any gain or loss is recognized.

There were no material capitalized exploratory drilling costs pending evaluation at December 31, 2013 and December 31, 2012.

Impairments

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates, less than expected production, drilling results, higher operating and development costs, or lower commodity prices. The estimated undiscounted future cash flows expected in connection with the property are compared to the carrying value of the property to determine if the carrying amount is recoverable. If the carrying value of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Impairment expense for the years ended December 31, 2013 and 2012 was approximately $6.6 million and $28.9 million, respectively.

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Nonproducing oil and natural gas properties, which consist of undeveloped leasehold costs and costs associated with the purchase of proved undeveloped reserves, are assessed for impairment on a property-by-property basis. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management.

Asset Retirement Obligations

An asset retirement obligation associated with retiring long-lived assets is recognized as a liability on a discounted basis in the period in which the legal obligation is incurred and becomes determinable, with an equal amount capitalized as an addition to oil and natural gas properties, which is allocated to expense over the useful life of the asset. Generally, oil and gas producing companies incur such a liability upon acquiring or drilling a well. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. Upon settlement of the liability, a gain or loss is recognized as a component of exploration costs to the extent the actual costs differ from the recorded liability. See Note 6 for further discussion of asset retirement obligations.

Oil and Gas Reserves

The estimates of proved oil and natural gas reserves utilized in the preparation of the consolidated and combined financial statements are estimated in accordance with the rules established by the SEC and the Financial Accounting Standards Board (FASB). These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements. Netherland, Sewell & Associates, Inc. (NSAI), our independent reserve engineers, was engaged to prepare our reserves estimates at December 31, 2013.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

Other Property & Equipment

Other property and equipment is stated at historical costs and is comprised primarily of vehicles, furniture, fixtures, and computer hardware and software. Depreciation of other property and equipment is calculated using the straight-line method generally based on estimated useful lives of three to five years.

Restricted Investments

Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Southern California oil and gas properties. These investments are classified as held-to-maturity, and such investments are stated at amortized cost. Interest earned on these investments is included in interest expense net in the statement of operations. The amortized cost of such investments is adjusted for amortization of premiums and accretion of discounts to maturity. Such amortization and accretion is displayed as a separate line item in the statement of operations. At December 31, 2013, these restricted investments consisted of money market deposit accounts, money market mutual funds, commercial paper, and U.S. Government securities. See Note 7 for additional information.

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Debt Issuance Costs

These costs are recorded on the balance sheet and amortized over the term of the associated debt using the straight-line method which approximates the effective yield method. Amortization expense, including write-offs of debt issuance costs, for the years ended December 31, 2013 and 2012 was approximately $8.3 million and $3.6 million, respectively.

Revenue Recognition

Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties due to third parties. Oil and natural gas revenues are recorded using the sales method. Under this method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of our proportionate share of the remaining recoverable reserves on the underlying properties. No significant imbalances existed at December 31, 2013 or 2012.

The following individual customers each accounted for 10% or more of total reported revenues for the period indicated:

	Years Ending December 31, 2013	2012
Consolidated & Combined:		
Energy Transfer Equity, L.P. and subsidiaries	35%	13%
MRD Segment:		
Energy Transfer Equity, L.P. and subsidiaries	77%	39%
Sunoco, Inc.(1)	n/a	15%
Dominion Gas Ventures LP	n/a	15%
MEMP Segment:		
Phillips 66(2)	15%	13%
ConocoPhillips(2)	n/a	14%

(1) Sunoco, Inc. became a subsidiary of Energy Transfer Equity, L.P. in October 2012.

(2) Phillips 66 was a subsidiary of ConocoPhillips through April 30, 2012. Accordingly, any revenues generated from Phillips 66 prior to May 1, 2012 were reported under ConocoPhillips.

Derivative Instruments

Commodity derivative financial instruments (e.g., swaps, floors, collars, and put options) are used to reduce the impact of natural gas and oil price fluctuations. Interest rate swaps are used to manage exposure to interest rate volatility, primarily as a result of variable rate borrowings under the credit facilities. Every derivative instrument is recorded on the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative s fair value are recognized in earnings as we have not elected hedge accounting for any of our derivative positions.

Income Tax

We are organized as a pass-through entity for federal income tax purposes. As a result, our members are responsible for federal income taxes on their share of our taxable income. Certain of our consolidated subsidiaries are taxed as corporations and subject to federal income taxes. We are also subject to the Texas margin tax and certain aspects of the tax make it similar to an income tax as the tax is assessed on 1% of taxable

MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

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margin apportioned to operations in Texas. Deferred taxes arise due to temporary differences between the financial statement carrying value of existing assets and liabilities and their respective tax basis. Deferred tax liabilities as of December 31, 2013 were approximately $3.2 million and total tax expense for the year was approximately $1.6 million. Deferred tax liabilities as of December 31, 2012 were approximately $3.1 million and total tax expense for the year was approximately $0.1 million.

We must recognize the tax effects of any uncertain tax positions we may adopt if the position taken by us is more likely than not sustainable based on its technical merits. If a tax position meets such criteria, the tax effect that would be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized. There were no uncertain tax positions that required recognition in the financial statements at December 31, 2013 or 2012.

Upon closing of the Offering, MRDC will be treated as a taxable C corporation and will be subject to federal and certain state income taxes. Accordingly, a pro forma income tax provision has been disclosed as if Memorial Resource was a taxable corporation for all periods presented. Pro forma tax expense was computed using a blended corporate level federal and state tax rate of 36.06% and 35.39% for the years ended December 31, 2013 and 2012, respectively.

Unaudited Pro Forma Earnings Per Share

Memorial Resource has presented pro forma earnings per share (EPS) for all periods presented. Pro forma net income (loss) per basic share is determined by dividing the pro forma net income (loss) available to common shareholders by the number of common shares expected to be outstanding immediately following the Offering.

The following sets forth the calculation of pro forma EPS for the periods indicated (in thousands, except per share amounts):

	For the Year Ended December 31, 2013	2012
Numerator:		
Pro forma net income (loss)	$ 97,797	$ 17,512
Noncontrolling interest in pro forma net (income) loss, net of tax	(31,861)	1,745
Previous owners interest in pro forma net (income) loss, net of tax	(6,899)	(24,111)
Pro forma net income (loss) available to common shareholders	$ 59,037	$ (4,854)
Denominator:		
Common shares outstanding immediately following the Offering(1)	193,676	193,676
Basic EPS	$ 0.31	$ (0.03)

Diluted EPS	$	0.30	$	(0.03)

(1) Includes dilutive effect of 1,176 restricted common shares.

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The following sets forth the calculation of our supplemental pro forma EPS, for the periods indicated (in thousands, except per share amounts):

	For the Year Ended December 31, 2013	2012
Numerator:		
Pro forma net income (loss)	$ 97,797	$ 17,512
Noncontrolling interest in pro forma net (income) loss, net of tax	(31,861)	1,745
Pro forma net income (loss) available to common shareholders	$ 65,936	$ 19,257
Denominator:		
Common shares outstanding immediately following the Offering(1)	193,676	193,676
Basic and diluted EPS	$ 0.34	$ 0.10

(1) Includes dilutive effect of 1,176 restricted common shares.

Our supplemental basic and diluted EPU includes all the earnings generated by the previous owners for all periods presented due to common control considerations.

Unit-Based Compensation Arrangements

The fair value of equity-classified awards (e.g., restricted common unit awards) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards are recognized over the requisite service or vesting period of an award based on the fair value of the award re-measured at each reporting period. Generally, no compensation expense is recognized for equity instruments that do not vest.

The governing documents of Memorial Resource and certain of its subsidiaries, including WildHorse and BlueStone, provide for the issuance of incentive units. The incentive units are subject to performance conditions that affect their vesting. Compensation cost is recognized only if the performance condition is probable of being satisfied at each reporting date.

See Note 10 and 11 for further information.

Current Accrued Liabilities

Current accrued liabilities consisted of the following at the dates indicated (in thousands):

	December 31, 2013	December 31, 2012
Accrued capital expenditures	$ 48,579	$ 14,352
Accrued lease operating expense	13,240	6,701
Accrued general and administrative expenses	14,485	2,290
Accrued ad valorem and production taxes	3,541	3,753
Accrued interest payable	11,934	1,239
Accrued environmental	577	1,012
Other miscellaneous, including operator advances	5,774	4,140
	$ 98,130	$ 33,487

MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

New Accounting Pronouncements

Offsetting Disclosure Requirements. In December 2011, the FASB issued an accounting standard update intended to enhance current disclosure requirements on offsetting financial assets and liabilities. In January 2013, the FASB issued an accounting standard update to clarify the scope of offsetting disclosure requirements. The new disclosure requirements required the disclosure of both gross and net information about derivatives, repurchase agreements and reverse purchase agreements, and securities borrowing and securities lending transactions eligible for offset on the balance sheet or subject to a master netting arrangement or similar agreement. Disclosure of collateral received and posted in connection with master netting agreements or similar arrangements is also required. The disclosures became effective for annual and interim periods beginning on or after January 1, 2013 and were applied retrospectively. The adoption of this new guidance did not have a significant impact on our financial statements.

Note 3. Acquisitions and Divestitures

The third party acquisitions discussed below were accounted for under the acquisition method of accounting. Accordingly, we conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while acquisition costs associated with the acquisitions were expensed as incurred. The operating revenues and expenses of acquired properties are included in the accompanying financial statements from their respective closing dates forward. The transactions were financed through capital contributions and borrowings under credit facilities.

The fair values of oil and natural gas properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural properties include estimates of: (i) economic reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital.

MEMP has consummated several common control acquisitions since completing its initial public offering in December 2011, as further discussed in Note 12, from certain affiliates of NGP. These acquisitions were each accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the net assets acquired were recorded at historical cost.

Acquisition-related costs

Acquisition-related costs for both related party and third party transactions are included in general and administrative expenses in the accompanying statements of operations for the periods indicated below (in thousands):

For the Year Ended December 31,

2013	2012
$8,313	$4,538

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2013 Acquisitions

On March 18, 2013, a purchase and sale agreement was executed by WildHorse for the purchase of certain oil and gas properties and leases in Louisiana from a third party (Louisiana Acquisition). The final adjusted purchase price was $67.1 million. This transaction closed on April 30, 2013. The following table summarizes the fair value of the third party assets acquired and liabilities assumed as of the acquisition date (in thousands):

	Louisiana Acquisition
Oil and gas properties	$ 68,887
Asset retirement obligations	(1,789)
Total identifiable net assets	$ 67,098

MEMP closed two separate transactions during the year ended December 31, 2013 to acquire certain oil and natural gas properties from third parties in East Texas (the East Texas Acquisition) and the Rockies (the Rockies Acquisition) for approximately $29.4 million in aggregate. The East Texas Acquisition closed on September 6, 2013 and the Rockies Acquisition closed on August 30, 2013. The following table summarizes the fair value of the third party assets acquired and liabilities assumed as of each acquisition date (in thousands):

	East Texas Acquisition	Rockies Acquisition
Oil and gas properties	$ 9,974	$ 20,744
Asset retirement obligations	(78)	(1,163)
Accrued liabilities		(118)
Total identifiable net assets	$ 9,896	$ 19,463

Propel Energy also acquired incremental interests in certain oil and gas properties and leases in the Hendrick Field located in Winkler County, Texas from two third parties in three separate transactions for approximately $9.3 million.

2012 Acquisitions

Third Party. On May 1, 2012, MEMP and WildHorse jointly acquired operating and non-operating interests in certain oil and natural gas properties located in East Texas and North Louisiana from an undisclosed third party seller (Undisclosed Seller Acquisition) for a final net purchase price of approximately $112.1 million. These properties are located primarily in Polk County, Texas and Lincoln and Claiborne

Parishes, Louisiana. During the year ended December 31, 2012, approximately $22.1 million of revenue and $9.2 million of earnings were recorded in the statement of operations related to the Undisclosed Seller Acquisition subsequent to the closing date.

On September 28, 2012, MEMP acquired certain oil and natural gas properties in East Texas from Goodrich Petroleum Corporation (Goodrich Acquisition) for a final net purchase price of $90.4 million after customary post-closing adjustments. The effective date of this transaction was July 1, 2012. This transaction was financed with borrowings under MEMP s revolving credit facility. These properties are located in the East Henderson field of Rusk County, Texas. During the year ended December 31, 2012, approximately $4.6 million of revenue and $2.0 million of earnings were recorded in the statement of operations related to the Goodrich Acquisition subsequent to the closing date.

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Collectively, the previous owners consummated multiple acquisitions during 2012 by acquiring operating and non-operating interests in certain oil and natural gas properties primarily located in various Texas and New Mexico counties for an aggregate adjusted purchase price of $147.9 million, the largest of which was completed in July by Stanolind. In July 2012, Stanolind completed an acquisition of working interests, royalty interests and net revenue interests (the Menemsha Acquisition) located in various counties in Texas for a final net purchase price of $74.7 million. During the year ended December 31, 2012, approximately $4.9 million of revenue and $0.9 million of earnings were recorded in the statement of operations related to the Menemsha Acquisition subsequent to the closing date.

The following table summarizes the fair value of the assets acquired and liabilities assumed as of each acquisition date (in thousands).

	Undisclosed Seller Acquisition	Goodrich Acquisition	Menemsha Acquisition	Other Previous Owner Acquisitions
Oil and gas properties	$ 115,633	$ 91,187	$ 75,114	$ 77,764
Prepaid expenses and other current assets		425		
Revenues payable	(1,602)	(875)		
Asset retirement obligations	(1,592)	(161)	(408)	(4,558)
Accrued liabilities	(297)	(153)		
Total identifiable net assets	$ 112,142	$ 90,423	$ 74,706	$ 73,206

The following unaudited pro forma combined results of operations are provided for the year ended December 31, 2012 (in thousands) as though the Undisclosed Seller Acquisition, Goodrich Acquisition, and Menemsha Acquisition had been completed on January 1, 2011. The unaudited pro forma financial information was derived from our historical combined statements of operations and adjusted to include: (i) the revenues and direct operating expenses associated with oil and gas properties acquired, (ii) depletion expense applied to the adjusted basis of the properties acquired and (iii) interest expense on additional borrowings necessary to finance the acquisitions. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transactions occurred on the basis assumed above, nor is such information indicative of expected future results of operations.

Revenues	431,061
Net income	40,940

During 2012, we also acquired certain interests in oil and gas properties through several individually immaterial acquisitions for an aggregate purchase price of $10.2 million.

Divestitures

On January 1, 2013, Tanos sold a natural gas gathering pipeline located in East Texas, which it had originally acquired in April 2010, to a privately held gas transportation company for a minimum of $1.5 million. The maximum allowable additional proceeds are $2.0 million. The contingent consideration is based on the natural gas pipeline servicing any new wells that Tanos drills in the area over the next three years. The contingent consideration portion of an arrangement is recorded when the consideration is determined to be realizable. Tanos recorded an aggregate gain of approximately $1.4 million related to this transaction, of which $0.4 million was contingent consideration. Tanos also sold certain non-operated oil and gas properties in 2013 for $2.9 million and recorded a gain of $1.4 million.

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On May 10, 2013, Black Diamond entered into a purchase and sale agreement with a third party to sell certain of its Wyoming oil and gas properties with an estimated net book value of $39.8 million for $33.0 million, before customary adjustments. As a result, Black Diamond recorded a loss on the sale of $6.8 million. This transaction closed on June 4, 2013.

BlueStone entered into an agreement with a publicly traded third party to sell its remaining interest in certain properties in the Mossy Grove Prospect in Walker and Madison Counties located in East Texas. Total cash consideration received by BlueStone was approximately $117.9 million, which exceeded the net book value of the properties sold by $89.5 million. The transaction closed on July 31, 2013.

During 2012, certain of our subsidiaries sold certain interests in oil and gas properties for an aggregate $3.3 million. Losses of approximately $0.1 million were recognized related to these divestures.

The previous owners sold certain interests in oil and gas properties offshore Louisiana on October 11, 2012 for an aggregate $40.1 million to an NGP controlled entity, of which $38.1 million was received upon closing. As of December 31, 2012, the remaining proceeds were held in escrow and included in restricted cash on the balance sheet. The remaining proceeds were released from escrow in April 2013. Due to common control considerations, the proceeds from the sale exceeded the net book value of the properties sold by $6.3 million and recognized in the equity statement as a net contribution.

On July 11, 2012, the previous owners completed the sale of a portion of its oil and gas assets located in Garza County, Texas to a third party for $26.1 million and recognized a gain of approximately $7.6 million. On September 18, 2012, the previous owners completed the sale of a portion of its oil and gas assets located in Ector County, Texas to a third party for $4.7 million and recognized a gain of approximately $2.2 million.

The majority of the proceeds generated from these sales were used to acquire operating and non-operating interests in certain oil and natural gas properties located primarily in various Texas and New Mexico counties.

Note 4. Fair Value Measurements of Financial Instruments

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk. A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

Level 1 Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. An active market is one in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. At December 31, 2013 and 2012, all of the derivative instruments reflected on the accompanying balance sheets were considered Level 2.

MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

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Level 3 Measure based on prices or valuation models that require inputs that are both significant to the fair value measurement and are less observable from objective sources (i.e., supported by little or no market activity).

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The carrying values of cash and cash equivalents, accounts receivables, accounts payables (including accrued liabilities) and amounts outstanding under long-term debt agreements included in the accompanying balance sheets approximated fair value at December 31, 2013 and 2012. The fair value estimates are based upon observable market data and are classified within Level 2 of the fair value hierarchy. These assets and liabilities are not presented in the following tables.

The fair market values of the derivative financial instruments reflected on the balance sheets as of December 31, 2013 and 2012 were based on estimated forward commodity prices and forward interest rate yield curves. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement in its entirety. The significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following table presents the derivative assets and liabilities that are measured at fair value on a recurring basis at December 31, 2013 and 2012 for each of the fair value hierarchy levels:

	Fair Value Measurements at December 31, 2013 Using			
	Quoted Prices in Active Market (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value
	(in thousands)			
Assets:				
Commodity derivatives	$	$ 105,054	$	$ 105,054
Interest rate derivatives		884		884
Total assets	$	$ 105,938	$	$ 105,938
Liabilities:				
Commodity derivatives		$ 58,234		$ 58,234
Interest rate derivatives		5,590		5,590
Total liabilities	$	$ 63,824	$	$ 63,824

	Fair Value Measurements at December 31, 2012 Using			
	Quoted Prices in Active Market (Level	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value

	1)		(in thousands)		
Assets:					
Commodity derivatives	$	$	95,586	$	$ 95,586
Liabilities:					
Commodity derivatives		$	45,938		$ 45,938
Interest rate derivatives			6,838		6,838
Total liabilities	$	$	52,776	$	$ 52,776

See Note 5 for additional information regarding our derivative instruments.

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NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis as reflected on the balance sheets. The following methods and assumptions are used to estimate the fair values:

The fair value of asset retirement obligations (AROs) is based on discounted cash flow projections using numerous estimates, assumptions, and judgments regarding such factors as the existence of a legal obligation for an ARO; amounts and timing of settlements; the credit-adjusted risk-free rate; and inflation rates. See Note 6 for a summary of changes in AROs.

If sufficient market data is not available, the determination of the fair values of proved and unproved properties acquired in transactions accounted for as business combinations are prepared by utilizing estimates of discounted cash flow projections. The factors to determine fair value include, but are not limited to, estimates of: (i) economic reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital.

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

During the year ended December 31, 2013, we recognized $6.6 million of impairments. The impairments primarily related to certain properties located in South Texas. The estimated future cash flows expected from South Texas properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on pricing terms specific to these properties.

During the year ended December 31, 2012, we recognized $28.9 million of impairments to proved oil and natural gas properties. Approximately $8.0 million related to a particular lease in the Elkhorn (Ellenburger) and Canyon Fields located in the Permian Basin as a result of a downward revision of estimated proved reserves due to unfavorable drilling results in the area. The remaining $20.9 million of impairments primarily related to certain fields in East Texas. The carrying values of these fields were determined to be unrecoverable due to a decline in gas prices.

Note 5. Risk Management and Derivative Instruments

Derivative instruments are utilized to manage exposure to commodity price and interest rate fluctuations and achieve a more predictable cash flow in connection with natural gas and oil sales from production and borrowing related activities. These transactions limit exposure to declines in prices or increases in interest rates, but also limit the benefits that would be realized if prices increase or interest rates decrease.

Certain inherent business risks are associated with commodity and interest derivative contracts, including market risk and credit risk. Market risk is the risk that the price of natural gas or oil will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the counterparty to a contract. It is our policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to our derivative contracts is a lender in our credit agreements. While collateral is generally not required to be posted by counterparties, credit risk associated with derivative instruments is minimized by limiting exposure to any single counterparty and entering into derivative instruments only with counterparties that are large financial institutions, which management believes present minimal credit risk. Additionally, master netting agreements are used to mitigate risk of loss due to default with

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counterparties on derivative instruments. We have also entered into the International Swaps and Derivatives Association Master Agreements (ISDA Agreements) with each of our counterparties. The terms of the ISDA Agreements provide us and each of our counterparties with rights of set-off upon the occurrence of defined acts of default by either us or our counterparty to a derivative, whereby the party not in default may set-off all liabilities owed to the defaulting party against all net derivative asset receivables from the defaulting party. See Note 8 for additional information in regards to our revolving credit facilities.

Commodity Derivatives

A combination of commodity derivatives (e.g., floating-for-fixed swaps, collars, call spreads and basis swaps) is used to manage exposure to commodity price volatility. Generally, natural gas derivative contracts are entered into and indexed to NYMEX Henry Hub and regional indices that are in proximity to our areas of production. Generally, oil derivative contracts are entered into and indexed to NYMEX WTI, Inter-Continental Exchange (ICE) Brent and California Midway-Sunset. Our NGL derivative contracts are indexed to OPIS Mont Belvieu. At December 31, 2013, the MRD Segment had the following open commodity positions:

	2014	2015	2016	2017
Natural Gas Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (MMBtu)	1,190,000	880,000	670,000	520,000
Weighted-average fixed price	$ 4.10	$ 4.19	$ 4.32	$ 4.45
Collar contracts:				
Average Monthly Volume (MMBtu)	330,000	130,000		
Weighted-average floor price	$ 4.09	$ 4.00	$	$
Weighted-average ceiling price	$ 5.24	$ 4.64	$	$
Basis swaps:				
Average Monthly Volume (MMBtu)	270,000	180,000	220,000	200,000
Spread	$ (0.07)	$ (0.09)	$ (0.08)	$ (0.08)
Crude Oil Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	18,000	6,000		
Weighted-average fixed price	$ 91.66	$ 88.50	$	$
Collar contracts:				
Average Monthly Volume (Bbls)	8,000	2,000		
Weighted-average floor price	$ 85.00	$ 85.00	$	$
Weighted-average ceiling price	$ 117.50	$ 101.35	$	$
NGL Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	18,000			
Weighted-average fixed price	$ 64.27			

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At December 31, 2013, the MEMP Segment had the following open commodity positions:

	2014	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (MMBtu)	2,575,458	2,145,278	2,342,442	2,230,067	2,060,000	1,814,583
Weighted-average fixed price	$ 4.34	$ 4.30	$ 4.42	$ 4.31	$ 4.52	$ 4.77
Collar contracts:						
Average Monthly Volume (MMBtu)	340,000	350,000				
Weighted-average floor price	$ 4.93	$ 4.62	$	$	$	$
Weighted-average ceiling price	$ 6.12	$ 5.80	$	$	$	$
Call spreads(1):						
Average Monthly Volume (MMBtu)	120,000	80,000				
Weighted-average sold strike price	$ 5.08	$ 5.25	$	$	$	$
Weighted-average bought strike price	$ 6.31	$ 6.75	$	$	$	$
Basis swaps:						
Average Monthly Volume (MMBtu)	2,822,083					
Spread	$ (0.09)	$	$	$	$	$
Crude Oil Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	136,444	148,281	142,313	130,600	122,000	40,000
Weighted-average fixed price	$ 95.82	$ 93.07	$ 86.85	$ 85.96	$ 85.62	$ 85.00
Collar contracts:						
Average Monthly Volume (Bbls)	23,000	5,000				
Weighted-average floor price	$ 82.83	$ 80.00	$	$	$	$
Weighted-average ceiling price	$ 105.31	$ 94.00	$	$	$	$
Basis swaps:						
Average Monthly Volume (Bbls)	57,292	57,500				
Spread	$ (9.21)	$ (9.73)	$	$	$	$
NGL Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	118,500	112,800				
Weighted-average fixed price	$ 36.23	$ 35.04	$	$	$	$

(1) These transactions were entered into for the purpose of eliminating the ceiling portion of certain collar arrangements, which effectively converted the applicable collars into swaps.

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Interest Rate Swaps

Periodically, we enter into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates such as those in our credit agreement to fixed interest rates. Conditions sometimes arise where actual borrowings are less than notional amounts hedged which has and could result in over-hedged amounts from an economic perspective. From time to time we enter into offsetting positions to avoid being economically over-hedged. At December 31, 2013, we had the following interest rate swap open positions:

Credit Facility (see Note 8)	2014	2015	2016
MEMP Segment:			
Average Monthly Notional (in thousands)	$ 173,958	$ 280,833	$ 150,000
Weighted-average fixed rate	1.306%	1.416%	1.193%
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR
MRD Segment:			
Average Monthly Notional (in thousands)	$ 118,750	$ 100,000	$
Weighted-average fixed rate	0.773%	0.758%	
Floating rate	1 Month LIBOR	1 Month LIBOR	

Balance Sheet Presentation

The following table summarizes the gross fair value of derivative instruments by the appropriate balance sheet classification even when the derivative instruments are subject to netting arrangements and qualify for net presentation on the balance sheet and the net recorded fair value as reflected on the balance sheet at December 31:

Type	Balance Sheet Location	Asset Derivatives 2013	Asset Derivatives 2012	Liability Derivatives 2013	Liability Derivatives 2012
		(in thousands)			
Commodity contracts	Short-term derivative instruments	$ 21,759	$ 48,901	$ 19,739	$ 8,072
Interest rate swaps	Short-term derivative instruments	845		3,287	3,575
Gross fair value		22,604	48,901	23,026	11,647
Netting arrangements	Short-term derivative instruments	(13,315)	(6,980)	(13,315)	(6,980)
Net recorded fair value	Short-term derivative instruments	$ 9,289	$ 41,921	$ 9,711	$ 4,667
Commodity contracts	Long-term derivative instruments	$ 83,295	$ 46,685	$ 38,495	$ 37,866
Interest rate swaps	Long-term derivative instruments	39		2,303	3,263
Gross fair value		83,334	46,685	40,798	41,129
Netting arrangements	Long-term derivative instruments	(34,718)	(29,506)	(34,718)	(29,506)

Net recorded fair value	Long-term derivative instruments	$ 48,616	$ 17,179	$ 6,080	$ 11,623

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Gains & Losses on Derivatives

We do not designate derivative instruments as hedging instruments for financial reporting purposes and neither did our predecessor. Accordingly, all gains and losses, including unrealized gains and losses from changes in the derivative instruments fair values, have been recorded in the accompanying statements of operations. The following table details the gains and losses related to derivative instruments for the years ending December 31, 2013 and 2012:

Derivative Instruments	Statements of Operations Location	Years Ended December 31, 2013	2012
		(in thousands)	
Commodity derivative contracts	(Gain) loss on commodity derivative instruments	$ (29,294)	$ (34,905)
Interest rate swaps	Interest expense, net	(239)	5,582

Note 6. Asset Retirement Obligations

Asset retirement obligations primarily relate to our portion of future plugging and abandonment of wells and related facilities. The following table represents a reconciliation of the asset retirement obligations for the years ended December 31, 2013 and 2012:

	2013	2012
	(in thousands)	
Asset retirement obligations at beginning of year	$ 102,380	$ 90,699
Liabilities added from acquisitions or drilling	4,227	7,962
Liabilities removed upon sale of wells	(1,765)	(1,931)
Liabilities removed upon plugging and abandoning	(170)	(119)
Accretion expense	5,581	5,009
Revision of estimates	1,516	760
Asset retirement obligations at end of year	111,769	102,380
Less: Current portion	90	390
Asset retirement obligations long-term portion	111,679	101,990

Note 7. Restricted Investments

Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Southern California oil and gas properties. The components of the restricted investment balance, which are all attributable to our MEMP Segment, are as follows at December 31:

	2013	2012
	(in thousands)	
BOEM platform abandonment (See Note 14)	$ 66,373	$ 61,389
BOEM lease bonds	794	776
SPBPC Collateral:		
Contractual pipeline and surface facilities abandonment (See Note 14)	2,306	1,959
California State Lands Commission pipeline right-of-way bond	3,005	3,000
City of Long Beach pipeline facility permit	500	500
Federal pipeline right-of-way bond	307	300
Port of Long Beach pipeline license	100	100
Restricted investments	$ 73,385	$ 68,024

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Note 8. Long Term Debt

Our debt obligations under revolving credit facilities consisted of the following at December 31:

	2013	2012
	(in thousands)	
MRD Segment:		
Memorial Resource $1.0 billion revolving credit facility, variable-rate, terminated December 2013	$	$ 80,000
10.00%/10.75% senior PIK toggle notes due December 2018(1)	350,000	
10.00%/10.75% senior PIK toggle notes unamortized discounts	(6,950)	
WildHorse $1.0 billion revolving credit facility, variable-rate, due April 2018	203,100	202,200
WildHorse $325.0 million second lien term facility, variable-rate, due December 2018	325,000	
Black Diamond $150.0 million revolving credit facility, variable-rate, terminated November 2013		27,000
BlueStone $150.0 million revolving credit facility, variable-rate, terminated August 2013		
Subtotal	871,150	309,200
MEMP Segment:		
MEMP $2.0 billion revolving credit facility, variable-rate, due March 2018	103,000	371,000
7.625% senior notes, fixed-rate, due May 1, 2021(2)	700,000	
7.625% senior notes unamortized discounts	(10,933)	
WHT $400.0 million revolving credit facility, variable-rate, terminated March 2013		89,300
Tanos $250.0 million revolving credit facility, variable-rate, terminated April 2013		25,250
Stanolind $250.0 million revolving credit facility, variable-rate, due July 2017		85,750
Boaz $75.0 million revolving credit facility, variable-rate, terminated October 2013		29,500
Crown $75.0 million revolving credit facility, variable-rate, terminated October 2013		13,882
Propel Energy $200.0 million revolving credit facility, variable-rate, due June 2015		15,500
Subtotal	792,067	630,182
Total long-term debt	$ 1,663,217	$ 939,382

(1) The estimated fair value of this fixed-rate debt was $348.3 million. The estimated fair value is based on quoted market prices and is classified as Level 2 within the fair value hierarchy.

(2) The estimated fair value of this fixed-rate debt was $721.0 million. The estimated fair value is based on quoted market prices and is classified as Level 2 within the fair value hierarchy.

Each of the revolving credit facilities contain customary covenants and restrictive provisions including but not limited to: (i) limitation on indebtedness and liens, (ii) limitations on restricted payments, (iii) limitation on investments and acquisitions, (iv) limitations on transactions with affiliates, (v) limitation on mergers, consolidation and asset sales, and (vi) limitations on commodity hedging and interest rate hedging. Each of the revolving credit facilities also includes financial maintenance covenants that require each borrower to meet certain financial performance criteria periodically (e.g., minimum interest coverage ratio and maximum leverage). The definitions and required ratios are set forth in each credit facility.

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Each of the credit facilities contain customary and other events of default including but not limited to: (i) failure to make payments when due, (ii) breach of any covenants continuing beyond the cure period, (iii) default under any other material debt, (iv) change in management or change of control, and (v) certain material adverse effects on the business of the loan parties. Upon an event of default, revolving credit commitments could be terminated and any outstanding indebtedness under such revolving credit facility, together with accrued interest, fees and other obligations under such credit facility, could be declared immediately due and payable.

Borrowing Base

Credit facilities tied to borrowing bases are common throughout the oil and gas industry. Each of the revolving credit facilities borrowing base is subject to redetermination on at least a semi-annual basis primarily based on estimated proved reserves. The borrowing base for each credit facility was the following at December 31:

	2013 (in thousands)
MRD Segment:	
WildHorse $1.0 billion revolving credit facility, variable-rate, due April 2018	300,000
MEMP Segment:	
MEMP $2.0 billion revolving credit facility, variable-rate, due March 2018	845,000
Total borrowing base	1,145,000

Weighted-Average Interest Rates

The following table presents the weighted-average interest rates paid on variable-rate debt obligations for the periods presented:

Credit facility	For the Year Ended December 31, 2013	2012
MRD Segment:		
Memorial Resource	3.17%	4.11%
Classic	n/a	4.50%
WildHorse revolver	2.30%	3.00%
WildHorse second lien	7.60%	n/a
Black Diamond	3.97%	3.62%
BlueStone	n/a	n/a
MEMP Segment:		
MEMP	3.25%	2.74%
Tanos	3.10%	2.31%
WHT	2.29%	2.60%

REO	n/a	3.40%
Stanolind	3.52%	3.76%
Crown	3.38%	4.20%
Propel Energy	3.08%	3.28%

Generally, borrowings under each revolving credit facility bear interest, at the borrower s option, at either: (i) the Alternative Base Rate (as defined within each credit facility) plus a margin that varies according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base

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then in effect), or (ii) the applicable LIBOR plus a margin that varies according to the borrowing base usage. The unused portion of the borrowing base will be subject a commitment fee that may vary from 0.375% to 0.50% per annum according to the borrowing base usage.

Memorial Resource Revolving Credit Agreement & Senior Notes

On July 13, 2012, Memorial Resource entered into a two-year $50.0 million senior secured revolving credit facility with an initial borrowing base of $35.0 million. Memorial Resource pledged 7,061,294 of MEMP common units and 5,360,912 of MEMP subordinated units as security under the revolving credit facility as well as its oil and gas properties and certain other assets of Memorial Resource. This revolving credit facility was also guaranteed by certain of Memorial Resource s wholly-owned subsidiaries.

On November 20, 2012, Memorial Resource entered into a first amendment to its credit agreement, which among other things: (i) increased the aggregate maximum credit to $1.0 billion, (ii) increased the borrowing base to $120.0 million and (iii) extended the maturity date to November 20, 2016. On April 25, 2013, Memorial Resource entered into a second amendment to its credit agreement, which among other things: (i) increased the borrowing base to $170.0 million and (ii) designated Tanos together with its consolidating subsidiaries as additional guarantors. On October 1, 2013, Tanos and its consolidating subsidiaries were removed as guarantors and the borrowing base was reduced to $120.0 million. On November 1, 2013, Memorial Resource entered into a third amendment to its credit agreement, which among other things: (i) designated Black Diamond together with its consolidating subsidiaries as additional guarantors, (ii) reduced the borrowing base to $100.0 million, and (iii) permitted second lien indebtedness. On November 22, 2013, the borrowing base was automatically reduced to $60.0 million upon Memorial Resource s sale of 7,061,294 MEMP common units in a secondary offering.

On December 18, 2013, indebtedness then outstanding under the revolving credit facility of $59.7 million and all accrued interest was paid off in full and the revolving credit facility was terminated in connection with the issuance of senior notes discussed below.

On December 18, 2013, Memorial Resource and its wholly-owned subsidiary, Memorial Resource Finance Corp. (MRD Finance Corp. and collectively, the MRD Issuers), completed a private placement of $350.0 million in aggregate principal amount of 10.00% / 10.75% Senior PIK Toggle Notes due 2018 (the PIK notes). The PIK notes were issued at 98% of par and will mature on December 15, 2018. Net proceeds from the private offering were used: (i) to repay all indebtedness then outstanding under Memorial Resource s revolving credit facility, (ii) to establish a cash reserve of $50.0 million for the payment of interest on the PIK notes, (iii) to pay a $210.0 million distribution to the Funds, and (iv) for general company purposes.

Interest on the PIK notes will be payable semi-annually in arrears on June 15 and December 15 of each year, commencing on June 15, 2014. Subject to conditions in the indenture governing the PIK notes, Memorial Resource will be required to pay interest on the PIK notes in cash or through issuing additional notes (such an issuance, PIK Interest). The interest rate on the PIK notes is 10.00% per annum for interest paid in cash or 10.75% per annum for PIK Interest. PIK Interest will be paid by issuing additional notes having the same terms as the PIK notes. The PIK notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any. The MRD Issuers may also be required to repurchase the PIK notes upon a change of control.

At the time the PIK notes were issued, all of Memorial Resource s subsidiaries other than MEMP and BlueStone (and their respective subsidiaries) were designated as restricted subsidiaries. The indenture governing the PIK notes contains customary covenants and restrictive provisions that apply to both Memorial Resource and its restricted subsidiaries, many of which will terminate if at any time no default exists under the indenture and

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the PIK notes receive an investment grade rating from both of two specified ratings agencies. The PIK notes are fully and unconditionally guaranteed on a senior unsecured basis by all of Memorial Resource s restricted subsidiaries, except MEMP GP, WildHorse and MRD Royalty LLC.

The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency, all outstanding PIK notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding PIK notes may declare all the PIK notes to be due and payable immediately.

Classic Revolving Credit Facility

On November 1, 2007, Classic entered into a four-year, $150.0 million revolving credit facility, which was collateralized by its oil and gas properties. The revolving credit facility was amended on June 21, 2010 to extend the maturity date to June 21, 2014. On November 20, 2012, indebtedness then outstanding under the revolving credit facility of $80.0 million and all accrued interest was paid off in full with borrowings under the Memorial Resource revolving credit facility and the Classic revolving credit facility was terminated.

WildHorse Revolving Credit Facility & Second Lien Facility

On May 12, 2010, WildHorse entered into a revolving credit facility. Borrowings under the amended revolving credit facility are secured by liens on substantially all of WildHorse s properties, but in any event, not less than 80% of the total value of the WildHorse s oil and natural gas properties.

On April 3, 2013, WildHorse entered into an amended and restated credit agreement. The new revolving credit facility provides for aggregate maximum credit amounts at any time of $1.0 billion, consisting of borrowings and letters of credit and has an initial borrowing base of $300.0 million. The new revolving credit facility matures on April 13, 2018. The borrowing base is subject to redetermination on at least a semi-annual basis. Borrowings under the revolving credit facility are secured by liens on substantially all of WildHorse s properties, but in any event, not less than 80% of the total value of the WildHorse s oil and natural gas properties.

On June 13, 2013, WildHorse entered into a $325.0 million second lien term loan agreement and matures on December 13, 2018. No amount of second lien term loans once repaid may be reborrowed. Borrowings bear interest, at the borrower s option, at either: (i) the Alternative Base Rate (as defined within each credit facility) plus 5.25% per annum or (ii) the applicable LIBOR plus 6.25% per annum. Borrowings under the second lien term loan agreement are secured by second-priority liens on substantially all of WildHorse s properties, but in any event, not less than 80% of the total value of the WildHorse s oil and natural gas properties. The priority of the security interests in the collateral and related creditors rights is set forth in an intercreditor agreement. The second lien term loan agreement contains customary affirmative and negative covenants, restrictive provisions and events of default.

On June 13, 2013, WildHorse borrowed $325.0 million under its second lien term loan agreement and used such borrowings to reduce outstanding indebtedness under its revolving credit facility and to pay a one-time special $225.0 million distribution to Memorial Resource. This $225.0 million distribution was subsequently distributed to NGP.

Black Diamond Revolving Credit Facility

On July 27, 2011, the Black Diamond entered into a second amended and restated revolving credit facility, which extended the maturity date of the original agreement to May 9, 2015. Borrowings under the revolving

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credit facility were collateralized by Black Diamond s oil and natural gas properties. On November 1, 2013, the Black Diamond revolving credit facility was terminated. There was no indebtedness outstanding or accrued interest payable on such date.

BlueStone Revolving Credit Facility

On July 8, 2009, BlueStone entered into a $150.0 million revolving credit facility with various lenders. The line of credit was available until July 8, 2012, at which time all principal and accrued interest amounts would have been payable. On June 25, 2010, BlueStone refinanced its existing credit agreement and entered into a new $150.0 million revolving credit facility. Amounts outstanding under this credit facility were payable on June 25, 2014. There were no amounts outstanding under these facilities at December 31, 2012. Borrowings under the revolving credit facility were secured by BlueStone s assets and its equity interests in its subsidiaries. On August 27, 2013, the BlueStone revolving credit facility was terminated. There was no indebtedness outstanding or accrued interest payable on such date.

MEMP Revolving Credit Facility & Senior Notes

OLLC is a party to a $2.0 billion revolving credit facility, which is guaranteed by MEMP and certain of its current and future subsidiaries. A sixth amendment to the credit agreement was entered into on September 23, 2013, which among other things: (i) increased the facility from $1.0 billion to $2.0 billion and (ii) increased the borrowing base from $480.0 million to $920.0 million upon the closing of MEMP s $603.0 million acquisition that closed October 1, 2013. The borrowing base was automatically reduced by $100.0 million in conjunction with the issuances of senior notes in April and May 2013 as discussed below in accordance with the terms of the credit facility. On October 10, 2013, the borrowing base was automatically reduced by $75.0 million in conjunction with the issuance of additional senior notes.

Borrowings under the revolving credit facility are secured by liens on substantially all of MEMP s properties, but in any event, not less than 80% of the total value of MEMP s oil and natural gas properties, and all of MEMP s equity interests in OLLC and any future guarantor subsidiaries (other than San Pedro Bay Pipeline Company) and all of MEMP s other assets including personal property.

On April 17, 2013, MEMP and its wholly-owned subsidiary, Memorial Production Finance Corporation (Finance Corp. and collectively, the Issuers), completed a private placement of $300.0 million aggregate principal amount of 7.625% senior unsecured notes due 2021 (the Senior Notes). The Senior Notes were issued at 98.521% of par and are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by all of MEMP s subsidiaries (other than Finance Corp., which is co-issuer of the Senior Notes, and certain immaterial subsidiaries). On May 23, 2013, the Issuers issued an additional $100.0 million aggregate principal amount of the Senior Notes at 102% of par. On October 10, 2013, the Issuers issued additional $300.0 million aggregate principal amounts at 97% of par. The Senior Notes will mature on May 1, 2021 with interest accruing at a rate of 7.625% per annum and payable semi-annually in arrears on May 1 and November 1 of each year, commencing November 1, 2013. The Senior Notes are governed by an indenture. The Senior Notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any. The Issuers may also be required to repurchase the Senior Notes upon a change of control. The indenture contains customary covenants and restrictive provisions, many of which will terminate if at any time no default exists under the indenture and the Senior Notes receive an investment grade rating from both of two specified ratings agencies. The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to either of the Issuers, all outstanding Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of

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the then outstanding Senior Notes may declare all the Senior Notes to be due and payable immediately. The Issuers have agreed pursuant to registration rights agreements to file an exchange offer registration statement or, under certain circumstances, a shelf registration statement with respect to the Senior Notes no later than April 17, 2014.

Tanos Revolving Credit Facility

On December 16, 2010, Tanos entered into an amended and restated credit agreement with various lenders, which consisted of a four-year, $250 million revolving credit facility, which was collateralized by Tanos oil and gas properties. On April 1, 2013, indebtedness then outstanding under the revolving credit facility of $27.0 million was repaid and on April 25, 2013 all accrued interest was paid off in full and the Tanos revolving credit facility was terminated.

WHT Revolving Credit Facility

On April 8, 2011, WHT entered into a revolving credit facility. Borrowings under the revolving credit facility were secured by liens on substantially all of WHT s properties, but in any event, not less than 80% of the total value of the WHT s oil and natural gas properties. On March 28, 2013, the debt balance then outstanding under the revolving credit facility of $89.3 million and all accrued interest was paid off in full and the WHT revolving credit facility was terminated.

Stanolind Revolving Credit Facility

On September 9, 2010, Stanolind entered into a multi-year $50.0 million senior secured revolving credit agreement, which is collateralized by substantially all of Stanolind s oil and gas properties. During 2012, the credit agreement was amended, which among other things: (i) increased the aggregate maximum credit to $250.0 million and (ii) increased the borrowing base to $75.0 million. The borrowing base was redetermined subsequent to the amendment date and set at $97.0 million. The maturity date of the credit facility was July 13, 2017. All of Stanolind s indebtedness outstanding under the revolving credit facility was attributable to Stanolind SPV. On October 1, 2013, the debt balance then outstanding under the revolving credit facility and all accrued interest was paid off in full by MEMP on behalf of Stanolind.

Boaz Revolving Credit Facility

On August 1, 2011, Boaz entered into a multi-year $75.0 million senior secured revolving credit agreement, which was collateralized by substantially all of Boaz s oil and gas properties. The maturity date of the credit facility was August 31, 2015. On October 1, 2013, the debt balance then outstanding under the revolving credit facility and all accrued interest was paid off in full and the Boaz revolving credit facility was terminated.

Crown Revolving Credit Facility

On January 28, 2010, Crown entered into a multi-year $75.0 million senior secured revolving credit agreement, which was collateralized by substantially all of Crown s oil and gas properties. The maturity date of the credit facility was October 25, 2016. On October 1, 2013, the debt balance then outstanding under the revolving credit facility and all accrued interest was paid off in full and the Crown revolving credit facility was terminated.

Propel Energy Revolving Credit Facility

On June 15, 2011, Propel Energy entered into a multi-year $200.0 million senior secured revolving credit agreement, which was collateralized by substantially all of Propel Energy s oil and gas properties. The maturity

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date of the credit facility was June 15, 2015. All of Propel Energy s indebtedness outstanding under the revolving credit facility was attributable to Propel SPV. On October 1, 2013, the debt balance then outstanding under the revolving credit facility and all accrued interest was paid off in full by MEMP on behalf of Propel Energy.

REO Revolving Credit Facility

On October 26, 2011, REO entered into a three-year, $150.0 million revolving credit facility, which was collateralized by its assets. On December 12, 2012, indebtedness then outstanding under the revolving credit facility of $28.5 million and all accrued interest was paid off in full and the revolving credit facility was terminated.

Unamortized Deferred Financing Costs

Unamortized deferred financing costs associated with our combined debt obligations were as follows at December 31:

	2013	2012
	(in thousands)	
MRD Segment:		
Memorial Resource revolving credit facility	$	$ 653
PIK notes	8,261	
Classic revolving credit facility		160
WildHorse revolving credit facility	2,436	921
WildHorse second lien term loan	9,030	
Black Diamond revolving credit facility		233
MEMP Segment:		
MEMP revolving credit facility	5,413	3,359
Senior Notes	15,053	
Tanos revolving credit facility		416
WHT revolving credit facility		1,419
Stanolind revolving credit facility		580
Boaz revolving credit facility		153
Crown revolving credit facility		96
Propel Energy revolving credit facility		236
	$ 40,193	$ 8,226

Note 9. Noncontrolling Interests

Noncontrolling interests is the portion of equity ownership in our majority-owned subsidiaries not attributable to us and primarily consists of the equity interests held by: (i) the limited partners of MEMP, excluding units held by MRD; (ii) a third party investor in the San Pedro Bay Pipeline Company; and (iii) certain current or former key employees of certain of our subsidiaries.

Distributions paid to the limited partners of MEMP primarily represent the quarterly cash distributions paid to MEMP s unitholders, excluding those paid to Memorial Resource.

Contributions received from limited partners of MEMP primarily represent net cash proceeds received from common unit offerings. On March 25, 2013, MEMP sold 9,775,000 of its common units in an underwritten equity offering, which generated net cash proceeds of approximately $171.8 million after deducting underwriting

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discounts and offering expenses. The net proceeds from this equity offering partially funded MEMP s acquisition of all of the outstanding equity interests in WHT. On October 8, 2013, MEMP sold 16,675,000 of its common units in an underwritten equity offering, which generated net cash proceeds of approximately $318.3 million after deducting underwriting discounts and offering expenses. The net proceeds from this equity offering were used to repay a portion of outstanding borrowings under the MEMP revolving credit facility. In December 2012, MEMP sold 11,975,000 of its common units in an underwritten equity offering, which generated net cash proceeds of $194.3 million. The net proceeds from this equity offering partially funded MEMP s December 2012 acquisition.

On April 1, 2013, Tanos management team sold its 1.066% interest in Tanos to Memorial Resource and all incentive units held were forfeited. See Note 11 for further information.

In connection with this sale, all of Tanos employees resigned and became employees of Tanos Exploration II, LLC (Tanos II), a Texas limited liability company controlled by the former management team of Tanos. Effective April 1, 2013, Tanos II entered into a transition services agreement with Tanos, whereby Tanos II would manage the operations of Tanos for up to a 6-month period of time. Tanos II is an unrelated entity.

On November 1, 2013, Memorial Resource purchased the noncontrolling interests in Black Diamond, Classic GP and Classic and all incentive units were forfeited. See Note 11 for further information.

In connection with the purchase of the remaining noncontrolling interests in Black Diamond, all of Black Diamond s employees resigned and certain of them became members of DBD Partners, LLC (DBD), a Delaware limited liability company controlled by the former management team of Black Diamond. Effective November 1, 2013, DBD entered into a transition services agreement with Black Diamond, whereby DBD would manager the operations of Black Diamond for up to a 12 month period of time. DBD is an unrelated entity.

Note 10. Long-Term Incentive Plan

In December 2011, the Memorial Production Partners GP LLC Long-Term Incentive Plan (LTIP) was adopted for employees, officers, consultants and directors of MEMP GP and any of its affiliates, including Memorial Resource, who perform services for MEMP. The LTIP consists of restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, other unit-based awards and unit awards. The LTIP initially limits the number of common units that may be delivered pursuant to awards under the plan to 2,142,221 common units. Common units that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. During the years ended December 31, 2013 and 2012, there were multiple awards of restricted common units that were granted under the LTIP to executive officers and independent directors of MEMP GP and other Memorial Resource employees who provide services for MEMP.

The restricted common units awarded are subject to restrictions on transferability, customary forfeiture provisions and graded vesting provisions. Award recipients have all the rights of a unitholder in MEMP with respect to the restricted common units, including the right to receive distributions thereon if and when distributions are made by MEMP to its unitholders (except with respect to the fourth quarter 2011 distribution that was paid in February 2012). The term restricted common unit represents a time-vested unit. Such awards are non-vested until the required service period expires.

Based on the market price per unit on the date of grant, the aggregate fair value of the restricted common units awarded to MEMP GP s executive officers and other Memorial Resource employees during the years ended December 31, 2013 and 2012 was $9.7 million and $5.0 million, respectively. The restricted common units granted are accounted for as equity-classified awards. The grant-date fair value net of estimated forfeitures is

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recognized as compensation cost on a straight-line basis over the requisite service period. The fair value of the restricted unit awards granted to the independent directors of MEMP GP are also recognized as compensation cost on a straight-line basis over the requisite service period. The compensation costs associated with these awards are recorded as general and administrative expenses.

The following table summarizes information regarding restricted common unit awards for the periods presented:

	Number of Units	Weighted Average Grant Date Fair Value per Unit(1)	
Restricted common units outstanding at January 1, 2012		$	
Granted(2)	287,943	$	18.07
Forfeited	(2,334)	$	17.14
Restricted common units outstanding at December 31, 2012	285,609	$	18.08
Granted(3)	524,718	$	18.83
Forfeited	(11,734)	$	17.24
Vested	(91,666)	$	18.31
Restricted common units outstanding at December 31, 2013	706,927	$	18.62

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.
(2) The aggregate grant date fair value of restricted common unit awards issued in 2012 was $5.2 million based on grant date market prices of MEMP ranging from of $17.14 to $18.58 per unit.
(3) The aggregate grant date fair value of restricted common unit awards issued in 2013 was $9.9 million based on grant date market prices of MEMP ranging from of $18.33 to $20.35 per unit.

The unrecognized compensation cost associated with restricted common unit awards was an aggregate $9.9 million at December 31, 2013, which will be recognized over a weighted-average period of 2.2 years.

Since the restricted common units are participating securities of MEMP, any distributions received by the restricted common unitholders are reflected as a component of cash distributions to noncontrolling interest as presented on our statements of consolidated and combined cash flows. During the years ended December 31, 2013 and 2012, the restricted common unitholders received a distribution of approximately $1.0 million and $0.2 million, respectively.

Note 11. Incentive Units

Each of the governing documents of BlueStone Holdings, Tanos, WildHorse, Classic, Black Diamond and Memorial Resource either currently provide or previously provided for the issuance of incentive units. The incentive units are subject to performance conditions that affects their vesting. Compensation cost is recognized only if the performance condition is probable of being satisfied at each reporting date.

BlueStone Holdings, Tanos, WildHorse, Classic, Black Diamond and Memorial Resource each granted incentive units to certain of its members who were key employees at the time of grant. Holders of incentive units are entitled to distributions ranging from 10% to 31.5% when declared, but only after cumulative distribution thresholds (payouts) have been achieved. Payouts are generally triggered after the recovery of specified members capital contributions plus a rate of return. On December 14, 2011 and in connection with MEMP s initial public offering, BlueStone Holdings Special Tier and Tier I unit holders vested in their respective awards. Tier I unit holders will participate in 16.5% of any future distributions made by BlueStone Holdings.

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Vesting of the incentive units is generally dependent upon an explicit service period, a fundamental change as defined in the respective governing document, and achievement of payout. All incentive units not vested are forfeited if an employee is no longer employed. All incentive units will be forfeited if a holder resigns whether the incentive units are vested or not. If the payouts have not yet occurred, then all incentive units, whether or not vested, will be forfeited automatically (unless extended).

Except for the following, no compensation cost has been recorded related to incentive units for the years ended December 31, 2013 and 2012:

During 2012, a special distribution of $9.5 million was approved and declared to the WildHorse incentive unit holders as an advance on a future potential final distribution. This special distribution was included in general and administrative expense in the accompanying statement of operations for the year ended December 31, 2012.

On April 1, 2013, Tanos management team sold its 1.066% interest in Tanos to Memorial Resource and all incentive units held were forfeited. Compensation expense of approximately $5.8 million was recorded by Tanos and recognized as general and administrative expense during April 2013.

Compensation expense of approximately $19.1 million was recorded by BlueStone and recognized as general and administrative expense during July 2013. Net proceeds generated from the sale of oil and gas properties (see Note 3) were used to pay the distribution.

On November 1, 2013, Memorial Resource purchased the noncontrolling interests in Black Diamond, Classic GP and Classic and all incentive units were forfeited. Total consideration remitted by Memorial Resource was approximately $28.5 million, of which $2.0 million is payable in quarterly installments commencing February 1, 2014. Compensation expense of approximately $12.6 million was recorded by Black Diamond, Classic GP and Classic in the aggregate and recognized as general and administrative expense during November 2013.

In connection with the PIK notes issued in December 2013, a special distribution of $10.0 million to holders of WildHorse s Tier 1 incentive units was deemed probable of occurring. This amount was recognized as compensation expense in December 2013 with a corresponding amount in accrued liabilities on our balance sheet at December 31, 2013 as payment was not made until January 2, 2014.

In connection with the Offering, certain former management members of WildHorse Resources will contribute their 0.1% membership interest in WildHorse as well as their incentive units in exchange for shares of common stock of MRDC and cash consideration. As such, WildHorse is expected to recognize additional compensation cost in 2014 upon the closing of the Offering.

Note 12. Related Party Transactions

Common Control Transactions between MEMP and Other Memorial Resource Subsidiaries

During the year ended December 31, 2012, MEMP acquired additional oil and natural gas properties from Tanos and Classic. MEMP acquired all of the outstanding membership interests in WHT from WildHorse and Tanos on March 28, 2013; acquired all the outstanding membership interests in Prospect Energy from Black Diamond on October 1, 2013; acquired all of the outstanding membership interests in Tanos from Memorial Resource on October 1, 2013; and acquired the MRD Assets from Memorial Resource on October 1, 2013. These intercompany transactions eliminate in preparation of our consolidated and combined financial statements.

Beta Acquisition

On December 12, 2012, MEMP acquired REO, which owns certain operating interests in producing and non-producing oil and gas properties offshore Southern California, from Rise for a purchase price of $270.6

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million, which included $3.0 million of working capital and other customary adjustments. The Beta acquisition was funded with borrowings under MEMP s revolving credit facility and the net proceeds generated from its December 12, 2012 public offering of common units. The effective date for this transaction was September 1, 2012. The acquired properties, which are referred to as the Beta properties, primarily consist of a 51.75% working interest in three Pacific Outer Continental Shelf blocks covering the Beta Field, and are located in federal waters approximately eleven miles offshore the Port of Long Beach, California. Associated facilities include three conventional wellhead and production processing platforms, a 17.5-mile pipeline and an onshore tankage and metering facility. Two of the platforms are bridge connected and stand in approximately 260 feet of water, while the third platform stands in approximately 700 feet of water. This acquisition was accounted for as a combination of entities under common control at historical cost in a manner similar to the pooling of interest method. MEMP recorded the following net assets (in thousands):

Cash and cash equivalents	$ 6,021
Accounts receivable	16,284
Short-term derivative instruments, net	2,926
Prepaid expenses and other current assets	4,521
Oil and natural gas properties, net	108,342
Restricted investments	68,009
Accounts payable	(9,092)
Accrued liabilities	(9,140)
Asset retirement obligations	(58,746)
Credit facilities	(28,500)
Deferred tax liability	(1,674)
Noncontrolling interest	(5,255)
Net assets	$ 93,696

An affiliate of REO collected a management fee for providing administrative services to REO. These administrative services included accounting, business development, finance, legal, information technology, insurance, government regulations, communications, regulatory, environmental and human resources services. REO incurred and paid management fees of $1.6 million during the year ended December 31, 2012. These management fees are presented as a component of general and administrative costs and expenses in the accompanying statements of operations.

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October 2013 Cinco Group Acquisition

On October 1, 2013, MEMP acquired, through equity and asset transactions, oil and natural gas properties primarily in the Permian Basin, East Texas and the Rockies from Memorial Resource and certain affiliates of NGP for an aggregate preliminary purchase price of approximately $603 million (subject to customary post-closing adjustments), of which approximately $507.1 million was received by certain affiliates of NGP. We refer to this transaction as the Cinco Group acquisition. The Cinco Group acquisition was funded with borrowings under MEMP s revolving credit facility. The Cinco Group acquisition was accounted for as a combination of entities under common control at historical cost in a manner similar to the pooling of interest method.

Cash and cash equivalents	$ 2,820
Accounts receivable	5,184
Prepaid expenses and other current assets	1,454
Oil and natural gas properties, net	342,759
Other long-term assets	344
Accounts payable	(2,346)
Revenue payable	(2,910)
Accrued liabilities	(1,799)
Short-term derivative instruments, net	(1,828)
Long-term derivative instruments, net	(826)
Asset retirement obligations	(9,606)
Credit facilities	(151,690)
Net assets	$ 181,556

Net Profits Interest Sold to NGP

Upon the completion of the 2010 Petrohawk and Clayton Williams acquisitions, WildHorse sold a net profits interest in these properties to NGPCIF. Upon the acquisition of the Petrohawk properties WildHorse immediately sold a net profits interest of 6.25% for all producing well bores and the right to participate in a 3.125% net profits interest in non-producing wellbores for the subject area for $19.5 million, or $19.1 million after adjustments. Upon the acquisition of the Clayton Williams properties, WildHorse immediately sold a net profits interest of 23.5% for all producing wellbores and the right to participate in a 10.0% net profits interest in non-producing wellbores for the subject area for $19.8 million, or $19.9 million after adjustments. No gain or loss was recorded from these two transactions.

The net profits agreements for these transactions provide for a fixed fee of $20,000 per month for overhead and management in lieu of COPAS (Council of Petroleum Accountants Societies) billings. The net profits agreements do not provide for an overhead adjustment factor for this monthly charge, as suggested by COPAS. Quarterly net payments are made to NGPCIF for its net profits interest in the Petrohawk and Clayton Williams acquisitions. The net payments include credits for revenue receipts which are offset with production costs, capital expenditures and the management fee and are adjusted for any acquisition settlements received or paid and any other miscellaneous adjustments. As required by such agreements, WildHorse cannot collect funds owed by NGPCIF to WildHorse, but WildHorse can net amounts due from future quarterly payments.

As a result of these transactions, WildHorse paid NGPCIF a total of $2.6 million and $2.3 million during 2013 and 2012, respectively. NGPCIF owed WildHorse $0.2 million at December 31, 2013. WildHorse owed NGPCIF $0.4 million at December 31, 2012.

On February 28, 2014, WildHorse repurchased these net profits interests from NGPCIF for a purchase price $63.4 million after customary adjustments. This acquisition was accounted for as a combination of entities under

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common control at historical cost in a manner similar to the pooling of interest method and our consolidated and combined financial statements presented herein have been retrospectively revised.

WildHorse Management Services Agreement

WildHorse Resources II, LLC (WHR II) is an independent energy company engaged in the acquisition, exploitation, and development of natural gas and crude oil properties. WHR II is a related party and was organized in the State of Delaware on June 3, 2013. A management services agreement was executed on August 8, 2013, where WildHorse began providing general, administrative and employee services to WHR II. On August 8, 2013, a management agreement between WildHorse and WHR II was executed where WildHorse was appointed the manager for WHR II with responsibilities including administrative and land services, operator services and financial and accounting services. As operator, WildHorse receives operated and non-operated revenues on behalf of WHR II and bills and receives joint interest billings. In addition, WildHorse pays for lease operating expenses and drilling costs on behalf of WHR II. On August 8, 2013, an asset and cost sharing agreement between WildHorse and WHR II was executed. As part of the agreement, shared WildHorse costs are allocated between WildHorse and WHR II in accordance with a sharing ratio. The sharing ratio is based on the previous quarters capital expenditures and number of operated wells. Company specific costs are billed directly to the appropriate entity. As a result of these agreements, WildHorse received net payments of $4.4 million from WHR II during 2013. WildHorse owed WHR II $2.4 million as of December 31, 2013.

Cinco Group Transition Service Agreements

MEMP entered into transition service agreements with Propel Energy, Stanolind, and Boaz Energy Partners to ensure that ownership, operation, and maintenance of acquired properties can be smoothly transitioned. The term of these agreements are from October 1, 2013 through February 28, 2014. MEMP expects to pay transition service fees of approximately $0.8 million in the aggregate under these agreements.

Other

Effective March 1, 2012, BlueStone entered into an agreement with CH4 Energy III, LLC, an NGP controlled entity, to sell an undivided 25% interest in certain properties in the Mossy Grove Prospect in Walker and Madison Counties located in East Texas. Total cash consideration received by BlueStone was approximately $7.0 million, which exceeded the net book value of the properties sold by $6.4 million. Due to common control considerations, the $6.4 million was recognized in the equity statement as a contribution. The transaction closed on July 13, 2012.

A company affiliated with one of the Classic s employees provided certain land-related services to Classic. Classic paid approximately $1.0 million to this company for these services in 2012.

Certain of the Cinco Group entities entered into an advisory service, reimbursement, and indemnification agreements with NGP. These agreements generally required that an annual advisory fee be paid to NGP. Fees paid under these agreements for the years ended December 31, 2013 and 2012 were approximately $0.3 million and $0.4 million, respectively. Certain of the Cinco Group entities also paid a financing fee equal to a percentage of the capital contributions raised by NGP. These fees were considered a syndication cost and reduced equity contributions for financing fees paid. Fees for the year ended December 31, 2012 was approximately $0.4 million. There were no fees for the year ended December 31, 2013.

During 2012, the previous owners received an equity contribution of $6.9 million of oil and gas properties in the Hendricks Field located in the Permian Basin of Texas by an NGP controlled entity. Due to common control considerations, this equity contribution was recorded at historical cost of the properties.

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During 2012, Boaz reimbursed a member of its management team approximately $0.3 million in general, administrative, and lease operating expenses related to an oral lease agreement between the member of management and a third party for a field office and yard located in Bronte, Texas.

See Note 3 for additional information regarding the divestiture of certain interests in oil and gas properties offshore Louisiana that the previous owners sold during 2012 to an NGP controlled entity.

Note 13. Business Segment Data

Our reportable business segments are organized in a manner that reflects how management manages those business activities.

We have two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties. Our reportable business segments are as follows:

- MRD reflects the combined operations of Memorial Resource, WildHorse, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating, and MEMP GP.
- MEMP reflects the combined operations of MEMP, including the previous owners and any dropdown transactions between MEMP and other Memorial Resource subsidiaries. See Note 1 for additional information regarding dropdown transactions between MEMP and other Memorial Resource subsidiaries.

We evaluate segment performance based on Adjusted EBITDA. Adjusted EBITDA is defined as net income (loss), plus interest expense; income tax expense; depreciation, depletion and amortization; impairment of goodwill and long-lived assets; accretion of asset retirement obligations; losses on commodity derivative contracts and cash settlements received; losses on sale of assets; unit-based compensation expenses; exploration costs; equity loss from MEMP (MRD Segment only); cash distributions from MEMP (MRD Segment only); acquisition related costs; amortization of investment premium; and other non-routine items, less interest income; income tax benefit; gains on commodity derivative contracts and cash settlements paid; equity income from MEMP (MRD Segment only); gains on sale of assets and other non-routine items.

Financial information presented for the MEMP business segment is derived from the underlying consolidated and combined financial statements of MEMP that are publicly available.

Segment revenues and expenses include intersegment transactions. Our combined totals reflect the elimination of intersegment transactions.

In the MRD Segment s individual financial statements, investments in the MEMP Segment that are included in the consolidated and combined financial statements are accounted for by the equity method.

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The following table presents selected business segment information for the periods indicated (in thousands):

	MRD	MEMP	Other Adjustments & Eliminations	Consolidated and Combined Totals
Total revenues:				
Year ended December 31, 2013	$ 231,558	$ 343,616	$ (151)	$ 575,023
Year ended December 31, 2012	138,814	258,423	(369)	396,868
Adjusted EBITDA:				
Year ended December 31, 2013(1)	197,903	222,185	(25,232)	394,856
Year ended December 31, 2012(1)	131,702	179,334	(23,447)	287,589
Segment assets:(2)				
As of December 31, 2013	1,281,134	1,552,307	(4,280)	2,829,161
As of December 31, 2012	1,102,406	1,489,404	(132,506)	2,459,304
Total expenditures for additions to long-lived assets:				
Year ended December 31, 2013	267,870	200,577		468,447
Year ended December 31, 2012	249,526	387,160		636,686

(1) Adjustments and eliminations for the years ended December 31, 2013 and 2012 include amounts related to the MRD s Segment equity investments in the MEMP Segment as well the elimination of $26.0 million and $19.3 million of cash distributions that MEMP paid Memorial Resource for the years ended December 31, 2013 and 2012, respectively, related to Memorial Resource s partnership interests in MEMP.

(2) Adjustments and eliminations primarily represent the elimination of the MRD s Segment equity investments in the MEMP Segment. The adjustment at December 31, 2013 also includes $49.9 million related to an impairment recognized by the MEMP Segment during 2013. This impairment did not exist on a consolidated basis.

Calculation of Reportable Segments Adjusted EBITDA

	For the Year Ended December 31, 2013		
	MRD	MEMP	Combined Totals
		(in thousands)	
Net income (loss)	$ 82,243	$ 20,268	$ 102,511
Interest expense, net	27,349	41,901	69,250
Income tax expense (benefit)	1,311	308	1,619
DD&A	87,043	97,269	184,312
Impairment of proved oil and natural gas properties	2,527	54,362	56,889
Accretion of AROs	728	4,853	5,581
(Gain) loss on commodity derivative instruments	(3,013)	(26,281)	(29,294)
Cash settlements received on commodity derivative instruments	12,240	19,879	32,119
Gain on sale of properties	(82,773)	(2,848)	(85,621)
Acquisition related costs	1,584	6,729	8,313
Incentive unit compensation expense	43,279	3,558	46,837
Non-cash compensation expense		1,057	1,057
Exploration costs	1,226	1,130	2,356
Equity (income) loss from MEMP	(1,847)		(1,847)

Cash distributions from MEMP	26,006		26,006
Adjusted EBITDA	$ 197,903	$ 222,185	$ 420,088

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	For the Year Ended December 31, 2012		
	MRD	MEMP	Combined Totals
		(in thousands)	
Net income (loss)	$ (14,641)	$ 46,518	$ 31,877
Interest expense, net	12,802	20,436	33,238
Income tax expense (benefit)	(178)	285	107
DD&A	62,636	76,036	138,672
Impairment of proved oil and natural gas properties	18,339	10,532	28,871
Accretion of AROs	632	4,377	5,009
(Gain) loss on commodity derivative instruments	(13,488)	(21,417)	(34,905)
Cash settlements received on commodity derivative instruments	30,188	44,111	74,299
Gain on sale of properties	(2)	(9,759)	(9,761)
Acquisition related costs	403	4,135	4,538
Incentive unit compensation expense	9,510	1,423	10,933
Exploration costs	7,337	2,463	9,800
Amortization of investment premium		194	194
Non-cash equity (income) loss from MEMP	(696)		(696)
Cash distributions from MEMP	19,263		19,263
Adjusted EBITDA	$ 132,105	$ 179,334	$ 311,439

The following table presents a reconciliation of total reportable segments Adjusted EBITDA to net income (loss) for each of the periods indicated.

	For the Years Ended December 31,	
	2013	2012
	(in thousands)	
Total Reportable Segments Adjusted EBITDA	$ 420,088	$ 311,439
Adjustment to reconcile Adjusted EBITDA to net income (loss):		
Interest expense, net	(69,250)	(33,238)
Income tax benefit (expense)	(1,619)	(107)
DD&A	(184,717)	(138,672)
Impairment of proved oil and natural gas properties	(6,600)	(28,871)
Accretion of AROs	(5,581)	(5,009)
Gains (losses) on commodity derivative instruments	29,294	34,905
Cash settlements received on commodity derivative instruments	(32,119)	(74,299)
Gain on sale of properties	85,621	9,761
Acquisition related costs	(8,313)	(4,538)
Incentive unit compensation expense	(46,837)	(10,933)
Non-cash compensation expense	(1,057)	
Exploration costs	(2,356)	(9,800)
Amortization of investment premium		(194)
Cash distributions from MEMP	(26,006)	(19,263)
Non-cash equity (income) loss from WHT & MRD Assets	784	(4,184)
Net income (loss)	$ 151,332	$ 26,997

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Included below is our consolidated and combined statement of operations disaggregated by reportable segment for the period indicated:

	For the Year Ended December 31, 2013			
	MRD	MEMP	Other Adjustments & Eliminations	Consolidated and Combined Totals
	(in thousands)			
Revenues:				
Oil & natural gas sales	$ 230,751	$ 341,197	$	$ 571,948
Other revenues	807	2,419	(151)	3,075
Total revenues	231,558	343,616	(151)	575,023
Costs and expenses:				
Lease operating	25,006	88,893	(259)	113,640
Pipeline operating		1,835		1,835
Exploration	1,226	1,130		2,356
Production and ad valorem taxes	9,362	17,784		27,146
Depreciation, depletion, and amortization	87,043	97,269	405	184,717
Impairment of proved oil and natural gas properties	2,527	54,362	(50,289)	6,600
General and administrative	81,758	43,495	105	125,358
Accretion of asset retirement obligations	728	4,853		5,581
(Gain) loss on commodity derivative instruments	(3,013)	(26,281)		(29,294)
(Gain) loss on sale of properties	(82,773)	(2,848)		(85,621)
Other, net	2	647		649
Total costs and expenses	121,866	281,139	(50,038)	352,967
Operating income	109,692	62,477	49,887	222,056
Other income (expense):				
Interest expense, net	(27,349)	(41,901)		(69,250)
Earnings from equity investments	1,066		(1,066)	
Other, net	145			145
Total other income (expense)	(26,138)	(41,901)	(1,066)	(69,105)
Income before income taxes	83,554	20,576	48,821	152,951
Income tax benefit (expense)	(1,311)	(308)		(1,619)
Net income	$ 82,243	$ 20,268	$ 48,821	$ 151,332

(1) During the year ended December 31, 2013 the MEMP Segment recorded impairments of $50.3 million related to certain properties in East Texas. Both the MRD and MEMP Segments own properties in the same field and on a consolidated basis the expected future cash flows exceeded the carrying value, and therefore, did not result in an impairment on a consolidated basis.

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	For the Year Ended December 31, 2012			
	MRD	MEMP	Other Adjustments & Eliminations	Consolidated and Combined Totals
	(in thousands)			
Revenues:				
Oil & natural gas sales	$ 138,032	$ 255,608	$ (9)	$ 393,631
Other revenues	782	2,815	(360)	3,237
Total revenues	138,814	258,423	(369)	396,868
Costs and expenses:				
Lease operating	24,438	80,116	(800)	103,754
Pipeline operating		2,114		2,114
Exploration	7,337	2,463		9,800
Production and ad valorem taxes	7,576	16,048		23,624
Depreciation, depletion, and amortization	62,636	76,036		138,672
Impairment of proved oil and natural gas properties	18,339	10,532		28,871
General and administrative	38,414	30,342	431	69,187
Accretion of asset retirement obligations	632	4,377		5,009
(Gain) loss on commodity derivative instruments	(13,488)	(21,417)		(34,905)
(Gain) loss on sale of properties	(2)	(9,759)		(9,761)
Other, net	364	138		502
Total costs and expenses	146,246	190,990	(369)	336,867
Operating income	(7,432)	67,433		60,001
Other income (expense):				
Interest expense, net	(12,802)	(20,436)		(33,238)
Amortization of investment premium		(194)		(194)
Earnings from equity investments	4,880		(4,880)	
Other, net	535			535
Total other income (expense)	(7,387)	(20,630)	(4,880)	(32,897)
Income before income taxes	(14,819)	46,803	(4,880)	27,104
Income tax benefit (expense)	178	(285)		(107)
Net income	$ (14,641)	$ 46,518	$ (4,880)	$ 26,997

Note 14. Commitments and Contingencies

Litigation & Environmental

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our financial position, results of operations or cash flows. At December 31, 2012, we had an accrued liability of approximately $0.1 million relating primarily to a matter that has been settled. We did not have an accrued liability at December 31, 2013.

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Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management s best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2013, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

The following table presents the activity of our environmental reserves for the periods presented:

	2013	2012
	(in thousands)	
Balance at beginning of period	$ 1,469	$ 1,747
Charged to costs and expenses		193
Payments	(892)	(471)
Balance at end of period	$ 577	$ 1,469

At December 31, 2013 and 2012, $0.6 million and $1.0 million, respectively, of our environmental reserves were classified as current liabilities in accrued liabilities.

Sinking Fund Trust Agreement

REO assumed an obligation with a third party to make payments into a sinking fund in connection with its 2009 acquisition of the Beta properties, the purpose of which is to provide funds adequate to decommission the portion of the San Pedro Bay pipeline that lies within California state waters and the surface facilities. Under the terms of the agreement, REO, as the operator of the properties, is obligated to make monthly deposits into the sinking fund account in an amount equal to $0.25 per barrel of oil and other liquid hydrocarbon produced from the acquired working interest. Interest earned in the account stays in the account. The obligation to fund ceases when the aggregate value of the account reaches $4.3 million. As of December 31, 2013, the gross account balance included in restricted investments was approximately $2.3 million. REO s maximum remaining obligation net to its 51.75% interest under the terms of the current agreement was $1.0 million at December 31, 2013.

Supplemental Bond for Decommissioning Liabilities Trust Agreement

REO assumed an obligation with the Bureau of Ocean Energy Management (BOEM) in connection with its 2009 acquisition of the Beta properties. Under the terms of the agreement dated March 1, 2007, the seller of the Beta properties was obligated to deliver a $90.0 million U.S. Treasury Note into a trust account for the decommissioning of the offshore production facilities. At the time of acquisition, all obligations under this existing agreement had been met.

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In January 2010, the BOEM issued a report that revised upward, the estimated cost of decommissioning. In June 2010, REO agreed to make additional quarterly payments to the trust account attributable to its net working interest of approximately $0.6 million beginning on June 30, 2010 until the payments and accrued interest attributable to REO equal $78.7 million by December 31, 2016. The trust account must maintain minimum balances attributable to REO s net working interest as follows (in thousands):

June 30, 2014	$ 68,310
June 30, 2015	$ 72,450
June 30, 2016	$ 76,590
December 31, 2016	$ 78,660

In the event the account balance is less than the contractual amount, the working interest owners must make additional payments. Interest income earned and deposited in the trust account mitigates the likelihood that additional payments will have to be made by the working interest owners. As of December 31, 2013, the maximum remaining obligation net to REO s interest was approximately $12.2 million.

The trust account is held by REO for the benefit of all working interest owners. The following is a summary of the gross held-to-maturity investments held in the trust account less the outside working interest owners share as of December 31, 2013 (in thousands):

Investment	Amortized Cost	Unrealized Gain (Loss)	Fair Market Value
U.S. Bank Money Market Cash Equivalent	$ 105,184	$	$ 105,184
U.S. Government Treasury Note, maturity of June 30, 2014, and 1.75% coupon	23,073	93	23,166
Less: Outside working interest owners share	(61,884)	(45)	(61,929)
	$ 66,373	$ 48	$ 66,421

Processing Plant Expansions by Third Party Gatherer

In 2012, WildHorse contracted with Regency Field Services LLC (the Gatherer) to expand their Dubach processing plant by up to 70 MMcf per day among other facility and infrastructure improvements. The expansion project was complete and fully operational by July 2013. WildHorse will pay a payback demand fee until the payback demand fees received by the Gatherer plus any third party fees equal 110% of the new facility cost. For each month from the commencement date through the month in which the payout date occurs, WildHorse will pay a payback demand fee equal to the monthly demand quantity (136,200 MMBtu per day) times $0.26 per MMBtu. In addition, for each MMBtu gathered in excess of the demand quantity, WildHorse will pay a payback demand fee of $0.26 per MMBtu.

In 2013, WildHorse contracted with the Gatherer to build a new high pressure pipeline from the dedicated area to the Gatherer s Dubberly processing plant in Webster Parish, LA amongst other pipeline and infrastructure improvements. The expansion project was complete and fully operational by mid-December 2013. WildHorse will pay a payback demand fee until the payback demand fees received by the Gatherer plus any third party fees equal to 110% of the pipeline and infrastructure improvement costs. For each month from the commencement date through the month in which the payout date occurs, WildHorse will pay a payback demand fee equal to the monthly demand fee times $0.31 per MMBtu. In addition, for each MMBtu gathered in excess of the demand quantity, WildHorse will pay a payback demand fee of $0.31 per MMBtu. The monthly demand quantity is 56,750 MMBtu per day from the Dubberly start-up date through one full year thereafter and then increasing to 113,500 MMBtu per day until payout.

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Pursuant to the agreement, the Gatherer is obligated to process gas up to the maximum daily quantity of 158,000 MMBtu per day from the commencement date of the Dubach facility expansion through the start-up of the Dubberly pipeline. With the start-up of the Dubberly pipeline, the Gatherer is obligated to process gas up to the maximum daily quantity of 214,750 MMBtu per day through one full year thereafter. From and after the first anniversary of the Dubberly start-up date, the Gatherer is obligated to process gas up to the maximum daily quantity of 271,500 MMbtu per day. WildHorse is obligated to deliver all volumes of gas produced from the dedicated area to the Gatherer up to the maximum daily quantity.

Total allowable costs for the Dubach Plant expansion and the Dubberly pipeline (new Facility Costs) cannot exceed $129.0 million. WildHorse expects that total payments by WildHorse to the Gatherer for the new Facility Costs will not exceed 60% of the total payment amounts after contributions made by other owners. Payments made will reduce revenue associated with the production and are reflected in our reserve report.

WildHorse s minimum commitments to the Gatherer, before other owner contributions, as of December 31, 2013 were as follows (in thousands):

	Dubach	Dubberly	Total Facility Costs
2014	$ 12,925	$ 6,421	$ 19,346
2015	12,925	12,842	25,767
2016	12,961	12,878	25,839
2017	12,925	12,842	25,767
2018	10,766	10,697	21,463
Total	$ 62,502	$ 55,680	$ 118,182

Subsequent event. The contract with the Gatherer for the Dubach processing plant was amended effective February 1, 2014 where the payback demand fee for the Dubach processing plant increased from $0.26 to $0.275 cents per MMbtu. Also, the contract with the Gatherer for the new high pressure pipeline was amended effective February 1, 2014 where the payback demand fee decreased from $0.31 to $0.275 cents per MMbtu.

WildHorse s minimum commitments to the Gatherer, before other owner contributions, as of February 1, 2014 were as follows (in thousands):

	Dubach	Dubberly	Total Facility Costs
2014	$ 12,510	$ 5,212	$ 17,722
2015	13,671	11,393	25,064
2016	13,709	11,424	25,133
2017	13,671	11,393	25,064
2018	12,772	10,643	23,415

Total	$ 66,333	$ 50,065	$ 116,398

Operating Leases

We have leases for offshore Southern California pipeline right-of-way use and office space. We also incur surface rentals related to our business operations. For the years ended December 31, 2013 and 2012, we recognized $8.3 million and $5.0 million, respectively, of rent expense.

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Amounts shown in the following table represent minimum lease payment obligations under non-cancelable operating leases with a remaining term in excess of one year as of December 31, 2013:

	Payment or Settlement due by Period						
Lease Obligations	Total	2014	2015	2016	2017	2018	Thereafter
	(in thousands)						
Operating leases	20,325	2,389	2,546	2,583	2,718	2,783	7,306

Drilling & Compression Services

We have entered into drilling and compression services agreements with various terms. Amounts shown in the following table represent our minimum commitments as of December 31, 2013:

	Payment or Settlement due by Period						
Service Agreements	Total	2014	2015	2016	2017	2018	Thereafter
	(in thousands)						
Drilling services	20,323	20,323					
Compression services	7,090	7,079	11				

WildHorse Letter of Credit and Certificate of Deposit

Standby letters of credit were issued to the Louisiana Office of Conservation and the Railroad Commission of Texas for the account of WildHorse for $1.2 million during 2011. The letters of credit are to insure compliance by WildHorse with regulatory requirements. These letters of credit are collateralized by two Certificates of Deposits; the fair value of the Certificates of Deposits was $0.5 million and $1.2 million at December 31, 2013 and 2012, respectively. The amount of the letter of credit and the Certificates of Deposit is adjusted depending on the requirements of the Office of Conservation. The Certificates of Deposit is classified as a restricted noncurrent asset and is not considered operating cash for the purposes of the statements of cash flows.

Note 15. Defined Contribution Plans

Memorial Resource sponsors a defined contribution plan for the benefit of substantially all employees who have attained 18 years of age. The plan allows eligible employees to make tax-deferred contributions up to 100% of their annual compensation, not to exceed annual limits established by the Internal Revenue Service. Memorial Resource makes matching contributions of 100% of employee contributions that does not exceed 6% of compensation. Employees are immediately vested in these matching contributions. The plan received employer contributions of approximately $0.9 million and $0.4 million in for the years ended December 31, 2013 and 2012, respectively.

Effective January 1, 2012, REO assumed sponsorship of a separate defined contribution plan. This plan specifically benefits substantially all those employed by the Memorial Resource subsidiary (Beta Operating) that operates and supports the Beta properties that have attained 21 years of age. Eligible employees are permitted to make tax-deferred contributions up to 100% of their annual compensation, not to exceed annual limits established by the Internal Revenue Service. Employer matching contributions of 100% of employee contributions that does not exceed 6% of compensation are made to the plan as well. The employer matching contributions associated with this plan were subject to a three-year graded vesting schedule through February 28, 2012. Effective March 1, 2012, the plan was amended to offer immediate vesting of employer matching contributions. The plan received employer contributions of approximately $0.6 million and $0.5 million in 2013 and 2012, respectively. Approximately $0.3 million associated with this plan are reflected as costs and expenses in the accompanying statements of operations for both the years ended December 31, 2013 and 2012, respectively.

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WildHorse, Tanos, BlueStone, Classic and Black Diamond also sponsor defined contribution plans for the benefit their eligible employees. Matching employer contributions of approximately $0.5 million and $0.6 million were made to these other plans in 2013 and 2012, respectively.

Crown and Stanolind also made matching contributions to defined contribution plans for the benefit of their eligible employees. Matching employer contributions of approximately $0.1 million were made to these plans in both 2013 and 2012. Such contributions to these plans are included in general and administrative expenses in the accompanying combined statements of operations.

Note 16. Subsequent Events

In preparing the consolidated and combined financial statements, management has evaluated all subsequent events and transactions for potential recognition or disclosure through April 4, 2014, the date the consolidated and combined financial statements were available for issuance.

Common Control Acquisition

On April 1, 2014, MEMP acquired certain oil and natural gas producing properties in East Texas from WildHorse for a purchase price of $34.0 million, subject to customary purchase price adjustments. This transaction was financed with borrowings under MEMP s revolving credit facility. The acquired properties primarily represent additional working interests in wells currently owned by MEMP and located primarily in Polk and Tyler Counties in the Double A Field of East Texas, as well as the Sunflower, Segno and Sugar Creek Fields.

3rd Party Acquisition

On March 25, 2014, MEMP acquired certain oil and gas producing properties in the Eagle Ford trend from Alta Mesa Holdings, LP for a purchase price of $173 million, subject to customary purchase price adjustments. The acquired properties are located in Karnes County in the core of the Eagle Ford oil window. The properties are 100% non-operated. In addition, MEMP acquired a 30% interest in the seller s Eagle Ford leasehold. MEMP acquired all of the seller s working and net revenue interest in the producing wells subject to a net profits interest retained by the seller that reduces annually and terminates after three years. At the end of three years, MEMP will own all of the seller s interests in the currently producing wells.

NGPCIF NPI Acquisition

See Notes 1 and 12 for further information regarding WildHorse s acquisition of NGPCIF NPI.

Recently Formed Subsidiaries

MRD Royalty LLC (MRD Royalty) and MRD Midstream LLC (MRD Midstream) were formed by Memorial Resource in 2014. MRD Royalty owns certain immaterial leasehold interests and overriding royalty interests in Texas and Montana. MRD Midstream owns an indirect interest in certain immaterial midstream assets in North Louisiana. Following the completion of the Offering, Memorial Resource will retain its ownership interest in MRD Royalty and MRD Midstream.

Gas Processing Agreement

On March 17, 2014, WildHorse entered into a gas processing agreement with PennTex North Louisiana, LLC (PennTex). PennTex is a joint venture among certain affiliates of NGP in which MRD Midstream owns a noncontrolling interest. Once PennTex s processing plant becomes operational, it will process natural gas

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produced from wells located on certain leases owned by WildHorse in the state of Louisiana. The agreement has a 15-year primary term, subject to one year extensions at either party s election. WildHorse will pay PennTex a monthly fee, subject to an annual inflationary escalation, based on volumes of natural gas delivered and processed. Once the plant is declared operational, WildHorse will be obligated to pay a minimum processing fee equal to approximately $18.3 million on an annual basis, subject to certain adjustments and conditions. The gas processing agreement requires that the processing plant be operational no later than November 1, 2015.

Note 17. Supplemental Oil and Gas Information (Unaudited)

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depreciation, depletion and amortization is as follows at the dates indicated.

	Years Ended December 31, 2013	2012
	(in thousands)	
MRD Segment:		
Evaluated oil and natural gas properties	$ 1,226,417	$ 1,052,219
Unevaluated oil and natural gas properties	46,413	26,589
Accumulated depletion, depreciation, and amortization	(256,629)	(202,581)
Subtotal	$ 1,016,201	$ 876,227
MEMP Segment:		
Evaluated oil and natural gas properties(1)	$ 1,758,953	$ 1,545,402
Unevaluated oil and natural gas properties		5,004
Accumulated depletion, depreciation, and amortization(1)	(416,617)	(265,710)
Subtotal	$ 1,342,336	$ 1,284,696
Eliminations:		
Accumulated depletion, depreciation, and amortization(1)	$ 49,884	$
Consolidated:		
Evaluated oil and natural gas properties(1)	$ 2,985,370	$ 2,597,621
Unevaluated oil and natural gas properties	46,413	31,593
Accumulated depletion, depreciation, and amortization(1)	(623,362)	(468,291)
Total	$ 2,408,421	$ 2,160,923

(1) Amounts do not include costs for SPBPC and related support equipment.

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Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows for the periods indicated:

	Years Ended December 31, 2013	2012
	(in thousands)	
MRD Segment:		
Property acquisition costs, proved	$ 56,108	$ 87,857
Property acquisition costs, unproved	19,975	5,293
Exploration and extension well costs	13,313	212
Development	210,440	135,951
Subtotal	$ 299,836	$ 229,313
MEMP Segment:		
Property acquisition costs, proved	$ 37,786	$ 278,246
Property acquisition costs, unproved		
Exploration and extension well costs		42,430
Development(1)	145,830	62,472
Subtotal	$ 183,616	$ 383,148
Consolidated:		
Property acquisition costs, proved	$ 93,894	$ 366,103
Property acquisition costs, unproved	19,975	5,293
Exploration and extension well costs	13,313	42,642
Development(1)	356,270	198,423
Total	$ 483,452	$ 612,461

(1) Amounts do not include costs for SPBPC and related support equipment.

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

As required by the FASB and SEC, the standardized measure of discounted future net cash flows presented below is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to proved reserves. We do not believe the standardized measure provides a reliable estimate of the expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time, and therefore, may cause significant variability in cash flows from year to year as prices change.

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of proved and proved developed oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the

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most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

We engaged NSAI to prepare reserves estimates for all of our estimated proved reserves (by volume) at December 31, 2013. All proved reserves are located in the United States and all prices are held constant in accordance with SEC rules.

The weighted-average benchmark product prices used for valuing the reserves are based upon the average of the first-day-of-the-month price for each month within the period January through December of each year presented:

	2013	2012
Oil ($/Bbl):		
Spot(1)	$ 93.42	$ 91.33
NGL ($/Bbl):		
Spot(1)	$ 93.42	$ 91.75
Natural Gas ($/MMbtu):		
Spot(2)	$ 3.67	$ 2.75

(1) The unweighted average West Texas Intermediate spot price was adjusted by lease for quality, transportation fees, and a regional price differential.
(2) The unweighted average Henry Hub spot price was adjusted by lease for energy content, compression charges, transportation fees, and regional price differentials.

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MRD Segment

The following tables set forth estimates of the net reserves as of December 31, 2013 and 2012, respectively:

	Year Ended December 31, 2013			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Equivalent (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of year	11,953	739,378	41,466	1,059,895
Extensions and discoveries	1,794	149,974	8,319	210,652
Purchase of minerals in place	211	31,815	1,017	39,183
Production	(665)	(34,092)	(1,457)	(46,819)
Sales of minerals in place	(599)	(14,137)	(1,573)	(27,169)
Revision of previous estimates	(1,383)	(70,684)	(5,196)	(110,165)
End of year(1)	11,311	802,254	42,576	1,125,577
Proved developed reserves:				
Beginning of year	3,082	245,449	12,321	337,869
End of year	3,402	263,797	13,904	367,641
Proved undeveloped reserves:				
Beginning of year	8,871	493,929	29,145	722,026
End of year	7,909	538,457	28,672	757,936

(1) Includes reserves of 41,077 MMcfe attributable to noncontrolling interests and the MRD Segment previous owners.

	Year Ended December 31, 2012			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Equivalent (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of year	10,834	929,335	53,031	1,312,533
Extensions and discoveries	689	42,019	2,778	62,819
Purchase of minerals in place	1,100	28,115	1,879	45,987
Production	(369)	(24,131)	(898)	(31,731)
Sales of minerals in place	(4)	(728)		(752)
Revision of previous estimates	(297)	(235,232)	(15,324)	(328,961)
End of year(1)	11,953	739,378	41,466	1,059,895
Proved developed reserves:				
Beginning of year	2,107	191,557	7,644	250,073
End of year	3,082	245,449	12,321	337,869

Proved undeveloped reserves:				
Beginning of year	8,727	737,778	45,387	1,062,460
End of year	8,871	493,929	29,145	722,026

(1) Includes reserves of 67,135 MMcfe attributable to noncontrolling interests and the MRD Segment previous owners.

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Noteworthy amounts included in the categories of proved reserve changes for the years ended December 31, 2013 and 2012 in the above tables include:

148.6 Bcfe of the increase in reserves for the year end December 31, 2013, through the category extensions and discoveries, was due to the WildHorse s horizontal redevelopment drilling program in the Terryville Complex in Lincoln Parish, Louisiana.

WildHorse acquired 43.5 Bcfe in multiple acquisitions during the year ended December 31, 2012, the largest being the Undisclosed Seller Acquisition. Downward revisions of previous estimates for estimated natural gas proved reserves was primarily the result of a decrease in natural gas prices.

See Note 3 for additional information on acquisitions and divestitures.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

The standardized measure of discounted future net cash flows is as follows:

	Years Ended December 31, 2013	2012
	(in thousands)	
Future cash inflows	$ 5,722,848	$ 4,921,192
Future production costs	(1,587,374)	(1,255,289)
Future development costs	(1,352,945)	(1,060,777)
Future net cash flows for estimated timing of cash flows(1)	2,782,529	2,605,126
10% annual discount for estimated timing of cash flows	(1,313,577)	(1,284,531)
Standardized measure of discounted future net cash flows(2)	$ 1,468,952	$ 1,320,595

(1) We are subject to the Texas Franchise tax which has a maximum effective rate of 0.7% of gross income apportioned to Texas to immateriality we have excluded the impact of this tax. However, had we not been a tax exempt entity future income tax for the years ended December 31, 2013 and 2012 would have been $760,433 and $647,464, respectively.

(2) Includes $63,422 and $78,518 attributable to both noncontrolling interests and the MRD Segment previous owners for the years ended December 31, 2013 and 2012, respectively.

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during each of the years in the two year period ended December 31, 2013:

	Years Ended December 31, 2013	2012
	(in thousands)	
Beginning of year	$ 1,320,595	$ 1,386,071
Sale of oil and natural gas produced, net of production costs	(196,444)	(107,316)
Purchase of minerals in place	51,177	98,384
Sale of minerals in place	(54,091)	
Extensions and discoveries	301,004	127,994
Changes in prices and costs	(11,336)	(402,202)
Previously estimated development costs incurred	87,297	64,390
Net changes in future development costs	57,353	(67,331)
Revisions of previous quantities	(186,804)	(176,788)
Accretion of discount	128,544	138,607
Change in production rates and other	(28,343)	258,786
End of year	$ 1,468,952	$ 1,320,595

MEMP Segment

The following tables set forth estimates of the net reserves as of December 31, 2013 and 2012, respectively:

	Year Ended December 31, 2013 Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Equivalent (MMcfe)
Proved developed and undeveloped reserves:				
Beginning of year	39,089	604,440	29,352	1,015,095
Extensions and discoveries	5,655	40,770	1,747	85,180
Purchase of minerals in place	119	16,294	258	18,554
Production	(1,764)	(35,924)	(1,632)	(56,303)
Sales of minerals in place				
Revision of previous estimates	(3,950)	(18,441)	(879)	(47,421)
End of year(1)	39,149	607,139	28,846	1,015,105
Proved developed reserves:				

Beginning of year	24,515	376,932	15,947	619,704
End of year	22,265	387,548	15,959	616,893
Proved undeveloped reserves:				
Beginning of year	14,574	227,508	13,405	395,391
End of year	16,884	219,591	12,887	398,212

(1) MRD Segment s share of these reserves is 89,837 MMcfe.

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

	Year Ended December 31, 2012			
	Oil (MBbls)	**Gas (MMcf)**	**NGLs (MBbls)**	**Equivalent (MMcfe)**
Proved developed and undeveloped reserves:				
Beginning of year	27,150	579,751	15,045	832,913
Extensions and discoveries	7,501	19,869	1,053	71,192
Purchase of minerals in place	11,336	113,617	7,095	224,202
Production	(1,519)	(29,744)	(745)	(43,329)
Sales of minerals in place	(4,214)	(4,214)		(29,499)
Revision of previous estimates	(1,165)	(74,839)	6,904	(40,384)
End of year(1)(2)	39,089	604,440	29,352	1,015,095
Proved developed reserves:				
Beginning of year	19,332	413,431	10,015	589,504
End of year	24,515	376,932	15,947	619,704
Proved undeveloped reserves:				
Beginning of year	7,818	166,320	5,030	243,409
End of year	14,574	227,508	13,405	395,391

(1) Includes reserves of 406,324 MMcfe attributable to common control acquisitions.
(2) MRD Segment s share of these reserves is 476,550 MMcfe.

Noteworthy amounts included in the categories of proved reserve changes for the years 2013 and 2012 in the above tables include:

MEMP acquired 224.2 Bcfe in multiple acquisitions during the year ended December 31, 2012, the largest being the Goodrich Acquisition of 148.9 Bcfe. Stanolind acquired 43.6 Bcfe through multiple acquisitions, the largest being the Menemsha Acquisition of 23.9 Bcfe. During the year ended December 31, 2012, Propel divested 19.0 Bcfe of offshore Louisiana oil and gas properties to an NGP controlled entity.

See Note 3 for additional information on acquisitions and divestitures.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR)

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

The standardized measure of discounted future net cash flows is as follows:

	Years Ended December 31, 2013	2012
	(in thousands)	
Future cash inflows	$ 6,892,150	$ 6,511,776
Future production costs	(2,719,024)	(2,258,554)
Future development costs	(685,858)	(620,944)
Future net cash flows for estimated timing of cash flows(1)	3,487,268	3,632,278
10% annual discount for estimated timing of cash flows	(1,879,156)	(2,042,362)
Standardized measure of discounted future net cash flows(2)(3)	$ 1,608,112	$ 1,589,916

(1) MEMP is subject to the Texas Franchise tax which has a maximum effective rate of 0.7% of gross income apportioned to Texas. Due to immateriality we have excluded the impact of this tax. MEMP is organized as a pass-through entity for income tax purposes. Had we not been a tax exempt entity our share of future income tax related to our ownership of MEMP for the years ended December 31, 2013 and 2012 would have been $61,300 and $306,297, respectively.

(2) Includes $503,021 attributable to the MEMP previous owners for the year ended December 31, 2012.

(3) MRD Segment s share of the standardized measure of discounted future net cash flows was $142,318 and $554,981 for the years ended December 31, 2013 and 2012, respectively.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during each of the years in the two year period ended December 31, 2013:

	Years Ended December 31, 2013	2012
	(in thousands)	
Beginning of year	$ 1,589,916	$ 1,499,414
Sale of oil and natural gas produced, net of production costs	(234,520)	(160,023)
Purchase of minerals in place	23,160	375,953
Sale of minerals in place		(154,963)
Extensions and discoveries	136,423	265,108
Changes in income taxes, net		1,947
Changes in prices and costs	(74,395)	(331,760)
Previously estimated development costs incurred	174,490	66,360
Net changes in future development costs	(74,867)	(1,140)
Revisions of previous quantities	(141,122)	(90,587)
Accretion of discount	158,991	150,136
Change in production rates and other	50,036	(30,529)
End of year	$ 1,608,112	$ 1,589,916

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR) SCHEDULE 1 CONDENSED FINANCIAL INFORMATION

Condensed balance sheets

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 19,293	$ 8,019
Restricted cash	35,000	
Accounts receivable:		
Affiliates	90,917	84,347
Other		3
Prepaid expenses and other current assets	2,802	707
Total current assets	148,012	93,076
Property and equipment, at cost:		
Furniture and fixtures	1,679	1,217
Accumulated depreciation, depletion and impairment	(547)	(199)
Oil and natural gas properties, net	1,132	1,018
Long-term derivative instruments		
Investments in subsidiaries	411,657	797,868
Investments in previous owners	40,331	233,433
Restricted cash	15,000	
Other long-term assets	6,596	259
Total assets	$ 622,728	$ 1,125,654
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 130	$ 161
Accrued liabilities	1,896	225
Total current liabilities	2,026	386
Long-term debt	343,050	80,000
Other long-term liabilities	135	221
Total liabilities	345,211	80,607
Commitments and contingencies		
Equity:		
Members	237,186	811,614
Previous Owners	40,331	233,433
Total liabilities and members equity	$ 622,728	$ 1,125,654

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR) SCHEDULE 1 CONDENSED FINANCIAL INFORMATION

Condensed statements of income

	For Year Ended December 31, 2013	2012
Costs and expenses:		
Depreciation, depletion, and amortization	348	195
General and administrative	20,111	10,176
(Gain) loss on commodity derivative instruments	546	
Total costs and expenses	21,005	10,371
Operating income	(21,005)	(10,371)
Other income (expense):		
Equity income (loss) from subsidiaries	114,974	2,970
Equity income (loss) from previous owners	10,790	37,318
Interest expense, net	(3,257)	(219)
Total other income (expense)	122,507	40,069
Net income (loss)	$ 101,502	$ 29,698

Condensed statements of cash flows

	For Year Ended December 31, 2013	2012
Net cash provided by (used in) operating activities	$ (3,556)	$ (75,088)
Cash flows from investing activities:		
Investments in subsidiaries	(40,666)	(718)
Additions to furniture and fixtures	(461)	(903)
Proceeds from changes in ownership interests in MEMP	135,012	
Changes in restricted cash	(50,000)	
Net cash (used in) provided by investing activities	43,885	(1,621)
Cash flows from financing activities:		
Advances on revolving credit facility		80,000
Payments on revolving credit facility	(80,000)	
Proceeds from issuance of senior notes	343,000	
Distributions received from subsidiaries (see Note 3)	448,349	
Loan origination fees	(8,042)	(802)
Distributions to the Funds	(732,362)	
Net cash (used in) provided by financing activities	(29,055)	79,198

Net change in cash and cash equivalents	11,274	2,489
Cash and cash equivalents, beginning of year	8,019	5,530
Cash and cash equivalents, end of year	$ 19,293	$ 8,019

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR) NOTES TO CONDENSED FINANCIAL INFORMATION

Note 1. Basis of Presentation

Memorial Resource Development LLC (Memorial Resource) is a Delaware limited liability company (the Company) formed on April 27, 2011 to own, acquire, exploit and develop oil and natural gas properties. Unless the context requires otherwise, references to we, us, our, or the Company are intended to mean the business and operations of Memorial Resource Development LLC and its consolidated subsidiaries. There are significant restrictions over the ability of Memorial Resource to obtain funds from certain of its consolidating subsidiaries through dividends, loans or advances. Accordingly, these condensed financial statements have been presented on a parent-only basis. Under a parent-only presentation, the investments of Memorial Resource in its consolidated subsidiaries are presented under the equity method of accounting. These parent-only financial statements should be read in conjunction with the consolidated financial statements of MRD LLC included elsewhere herein. These condensed financial statements have been prepared in anticipation of a proposed initial public offering of the common stock of Memorial Resource Development Corp. (MRDC).

Note 2. Long-Term Debt

Our debt obligations under revolving credit facilities consisted of the following at December 31:

	2013	2012
	(in thousands)	
Memorial Resource $1.0 billion revolving credit facility, variable-rate, terminated December 2013	$	$ 80,000
10.00%/10.75% senior PIK toggle notes due December 2018	350,000	
10.00%/10.75% senior PIK toggle notes unamortized discounts	(6,950)	
Total long-term debt	$ 343,050	$ 80,000

On July 13, 2012, Memorial Resource entered into a two-year $50.0 million senior secured revolving credit with an initial borrowing base of $35.0 million. Memorial Resource pledged 7,061,294 of Memorial Production Partners LP (MEMP) common units and 5,360,912 of MEMP subordinated units as security under the credit facility as well as its oil and gas properties and certain other assets of Memorial Resource. This credit facility was also guaranteed by certain of Memorial Resources wholly-owned subsidiaries.

On November 20, 2012, Memorial Resource entered into a first amendment to its credit agreement, which among other things: (i) increased the aggregate maximum credit to $1.0 billion (ii) increased the borrowing base to $120.0 million and (iii) extended the maturity date to November 20, 2016. On April 25, 2013, Memorial Resource entered into a second amendment to its credit agreement, which among other things: (i) increased the borrowing base to $170.0 million and (ii) designated Tanos together with its consolidating subsidiaries as additional guarantors. On October 1, 2013, Tanos Energy, LLC (Tanos) and its consolidating subsidiaries were removed as guarantors and the borrowing base was reduced to $120.0 million. On November 1, 2013, Memorial Resource entered into a third amendment to its credit agreement, which among other things: (i) designated Black Diamond Minerals, LLC (Black Diamond) together with its consolidating subsidiaries as additional guarantors, (ii) reduced the borrowing base to $100.0 million, and (iii) permitted second lien indebtedness. On November 22, 2013, the borrowing base was automatically reduced to $60.0 million upon Memorial Resource s sale of 7,061,294 MEMP common units in a secondary offering.

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MEMORIAL RESOURCE DEVELOPMENT LLC (PREDECESSOR) NOTES TO CONDENSED FINANCIAL INFORMATION

On December 18, 2013, indebtedness then outstanding under the revolving credit facility of $59.7 million and all accrued interest was paid off in full and the revolving credit facility was terminated in connection with the issuance of senior notes discussed below.

On December 18, 2013, Memorial Resource and its wholly-owned subsidiary, Memorial Resource Finance Corp. (MRD Finance Corp. and collectively, the MRD Issuers), completed a private placement of $350.0 million in aggregate principal amount of 10.00% / 10.75% Senior PIK Toggle Notes due 2018 (the PIK notes). The PIK notes were issued at 98% of par and will mature on December 15, 2018. Net proceeds from the private offering were used: (i) to repay all indebtedness then outstanding under Memorial Resource s revolving credit facility, (ii) to establish a cash reserve of $50.0 million for the payment of interest on the PIK notes, (iii) to pay a $220.0 million distribution to the Funds, and (iv) for general company purposes.

Interest on the PIK notes will be payable semi-annually in arrears on June 15 and December 15 of each year, commencing on June 15, 2014. Subject to conditions in the indenture governing the PIK notes, Memorial Resource will be required to pay interest on the PIK notes in cash or through issuing additional notes (such an issuance, PIK Interest). The interest rate on the PIK notes is 10.00% per annum for interest paid in cash or 10.75% per annum for PIK Interest. PIK Interest will be paid by issuing additional notes having the same terms as the PIK notes. The PIK notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any. The MRD Issuers may also be required to repurchase the PIK notes upon a change of control.

At the time the PIK notes were issued, all of Memorial Resource s subsidiaries other than MEMP and BlueStone Holdings (and their respective subsidiaries) were designated as restricted subsidiaries. The indenture governing the PIK notes contains customary covenants and restrictive provisions that apply to both Memorial Resource and its restricted subsidiaries, many of which will terminate if at any time no default exists under the indenture and the PIK notes receive an investment grade rating from both of two specified ratings agencies. The PIK notes are fully and unconditionally guaranteed on a senior unsecured basis by all of Memorial Resource s restricted subsidiaries, except MEMP GP and WildHorse.

The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency, all outstanding PIK notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding PIK notes may declare all the PIK notes to be due and payable immediately.

Note 3. Distribution from subsidiaries

The table below shows the distributions received from our subsidiaries classified as inflows from operating activities for the periods indicated since they are represent return on investment:

	For Year Ended December 31,	
	2013	2012
	(in thousands)	

Distributions received from subsidiaries	$ 25,966	$ 19,228

Distributions received from our subsidiaries that represent return of investment are classified as inflows from investing activities.

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Independent Auditors Report

The Members

Merit Energy Company, LLC:

We have audited the accompanying statements of revenues and direct operating expenses of Merit Energy Company s oil and gas properties under contract for purchase by Memorial Production Partners LP (the Properties) for each of the years in the three-year period ended December 31, 2013.

Management s Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity s preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity s internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly in all material respects, the revenues and direct operating expenses of Merit Energy Company s oil and gas properties under contract for purchase by Memorial Production Partners LP for each of the years in the three-year period ended December 31, 2013, in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Dallas, TX

May 30, 2014

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STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE OIL AND GAS PROPERTIES UNDER CONTRACT FOR PURCHASE BY

MEMORIAL PRODUCTION PARTNERS LP FROM MERIT ENERGY

(In thousands)

	Six Months Ended June 30,		Year Ended December 31,		
	2014	2013	2013	2012	2011
	(unaudited)				
Revenues:					
Oil Sales	$ 76,836	$ 73,914	$ 156,981	$ 164,124	$ 172,828
NGL Sales	14,363	14,758	29,440	30,363	33,101
	91,199	88,672	186,421	194,487	205,929
Direct Operating Expenses:					
Lease Operating Expenses	24,608	25,488	53,104	53,250	52,010
Production and Ad Valorem Taxes	11,943	11,625	26,810	23,757	25,244
	36,551	37,113	79,914	77,007	77,254
Excess of Revenues over Direct Operating Expenses	$ 54,648	$ 51,559	$ 106,507	$ 117,480	$ 128,675

See accompanying Notes to Statements of Revenues and Direct Operating Expenses

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NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE OIL AND GAS PROPERTIES UNDER CONTRACT FOR PURCHASE BY

MEMORIAL PRODUCTION PARTNERS LP FROM MERIT ENERGY

SIX MONTHS ENDED JUNE 30, 2014 AND 2013 (UNAUDITED)

AND THE YEARS ENDED DECEMBER 31, 2013, 2012 AND 2011

NOTE 1 BASIS OF PRESENTATION

On May 5, 2014, Memorial Production Partners LP (Memorial) entered into a Purchase and Sale agreement (PSA) with Merit Energy Company and certain of its affiliates (Merit Energy) to purchase oil and gas properties and related facilities located in the Lost Soldier and Wertz fields in Wyoming as further defined in the PSA (the Properties) for approximately $935 million, subject to normal closing adjustments, with an effective date of April 1, 2014. The accompanying statements of revenues and direct operating expenses relate only to the Properties.

Historical financial statements prepared in accordance with accounting principles generally accepted in the United States of America have never been prepared for the Properties. During the periods presented, the Properties were not accounted for or operated as a consolidated entity or as a separate division by Merit Energy. The accompanying statements of revenues and direct operating expenses related to the Properties were prepared from the historical accounting records of Merit Energy.

Certain indirect expenses, as further described in Note 4, were not allocated to the Properties and have been excluded from the accompanying statements. Any attempt to allocate these expenses would require significant and judgmental allocations, which would be arbitrary and may not be indicative of the performance of the properties on a stand-alone basis.

These statements of revenues and direct operating expenses do not represent a complete set of financial statements reflecting the financial position, results of operations, stakeholder s equity and cash flows of the Properties and are not necessarily indicative of the results of operations for the Properties going forward.

The accompanying statements of revenues and direct operating expenses for the six months ended June 30, 2014 and 2013 are unaudited but, in the opinion of management, include all adjustments (consisting of normal recurring adjustments) that are necessary for a fair presentation of the revenues and direct operating expenses of the Properties for those periods.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Revenue Recognition

Merit Energy utilizes the sales method of accounting for oil and natural gas liquids revenues whereby revenues, net of royalties, are recognized based on the actual volumes of oil and natural gas liquids production sold to purchasers. The amount of natural gas liquids sold may differ from the amount to which Merit Energy is entitled based on its revenue interests in the properties.

Direct Operating Expenses

Direct operating expenses, which are recognized on an accrual basis, relate to the direct expenses of operating the Properties. The direct operating expenses include lease operating, ad valorem tax and production tax expense. Lease operating expenses include lifting costs, well repair expenses, surface repair expenses, well workover costs and other field expenses. Lease operating expenses also include expenses directly associated with support personnel, support services, equipment and facilities directly related to oil and natural gas production activities.

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NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE OIL AND GAS PROPERTIES UNDER CONTRACT FOR PURCHASE BY

MEMORIAL PRODUCTION PARTNERS LP FROM MERIT ENERGY

SIX MONTHS ENDED JUNE 30, 2014 AND 2013 (UNAUDITED)

AND THE YEARS ENDED DECEMBER 31, 2013, 2012 AND 2011

NOTE 3 CONTINGENCIES

The activities of the Properties are subject to potential claims and litigation in the normal course of operations. Merit Energy management does not believe that any liability resulting from any pending or threatened litigation will have a material adverse effect on the operations or financial results of the Properties.

NOTE 4 EXCLUDED EXPENSES

The Properties are part of a much larger enterprise prior to their sale by Merit Energy to Memorial. Indirect general and administrative expenses, interest, income taxes, and other indirect expenses were not allocated to the Properties and have been excluded from the accompanying statements. In addition, any allocation of such indirect expenses may not be indicative of costs which would have been incurred by the Properties on a stand-alone basis.

Depreciation, depletion, and amortization have been excluded from the accompanying statements of revenues and direct operating expenses as such amounts would not be indicative of the depletion calculated on the Properties on a stand-alone basis.

NOTE 5 SUPPLEMENTARY OIL AND GAS INFORMATION (UNAUDITED)

Estimated Net Quantities of Oil and Natural Gas Reserves

The estimates of Proved Oil and Gas Reserves as of December 31, 2013, 2012, 2011 and 2010 were prepared for Merit Energy utilizing year-end estimates of reserve quantities provided by third-party independent petroleum engineering consultants. The estimated proved net recoverable reserves presented below include only those quantities that were expected to be commercially recoverable at the SEC applicable prices and costs for each year under the then existing regulatory practices and with conventional equipment and operating methods. Proved Developed Reserves represent only those reserves estimated to be recovered through existing wells. Proved Undeveloped Reserves include those reserves that may be recovered from new wells on undrilled acreage or from existing wells on which a relatively major expenditure for recompletion or secondary recovery operation is required. All of the Properties Proved Reserves set forth herein are located in Wyoming. The estimate of reserves, and the standardized measure of discounted future net cash flows shown below reflect Merit Energy s development plan for the Properties rather than Memorial s development plan for those Properties.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of our oil and natural gas properties. Estimates of fair value should also consider unproved reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is subjective and imprecise.

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NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE OIL AND GAS PROPERTIES UNDER CONTRACT FOR PURCHASE BY

MEMORIAL PRODUCTION PARTNERS LP FROM MERIT ENERGY

SIX MONTHS ENDED JUNE 30, 2014 AND 2013 (UNAUDITED)

AND THE YEARS ENDED DECEMBER 31, 2013, 2012 AND 2011

The following table sets forth estimates of the proved oil and natural gas liquids reserves (net of royalty interests) for the Properties and changes therein, for the periods indicated. The Properties do not contain any natural gas reserves.

	Oil (BBLS)	NGLs (BBLS)
Proved Reserves:		
Balance at December 31, 2010	30,000,203	4,930,909
Production	(1,914,904)	(400,732)
Revisions	3,513,342	351,376
Balance at December 31, 2011	31,598,641	4,881,553
Production	(1,851,220)	(401,615)
Revisions	169,319	416,981
Balance at December 31, 2012	29,916,740	4,896,919
Production	(1,691,073)	(390,554)
Revisions	349,622	72,830
Balance at December 31, 2013	28,575,289	4,579,195

	Oil (BBLS)	NGLs (BBLS)
Proved Developed Reserves:		
Balance at December 31, 2011	28,508,789	4,881,553
Balance at December 31, 2012	27,684,578	4,896,919
Balance at December 31, 2013	26,839,275	4,579,195

Standardized Measure of Discounted Future Net Cash Flows

We have summarized the Standardized Measure related to our proved oil and natural gas liquids reserves. We have based the following summary on a valuation of Proved Reserves using discounted cash flows based on SEC pricing applicable for each year, costs and economic conditions and a 10% discount rate. The additions to Proved Reserves from the purchase of reserves in place and new discoveries and extensions could vary significantly from year to year; additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant. Accordingly, you should not view the information presented below as an estimate of the fair value of our oil and natural gas properties, nor should you consider the information indicative of any trends.

Standardized Measure of Oil and Gas

in thousands	December 31, 2013	2012	2011
Future Cash Inflows	$ 2,977,811	$ 3,058,631	$ 3,264,063
Future Production Costs	(1,266,229)	(1,384,561)	(1,449,956)
Future Development Costs	(76,400)	(92,700)	(90,300)
Future Net Cash Flows	1,635,182	1,581,370	1,723,807
Discount of 10% per annum	(741,493)	(758,071)	(850,438)
Standardized Measure of Discounted Future Net Cash Flows	$ 893,689	$ 823,299	$ 873,369

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NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

OF THE OIL AND GAS PROPERTIES UNDER CONTRACT FOR PURCHASE BY

MEMORIAL PRODUCTION PARTNERS LP FROM MERIT ENERGY

SIX MONTHS ENDED JUNE 30, 2014 AND 2013 (UNAUDITED)

AND THE YEARS ENDED DECEMBER 31, 2013, 2012 AND 2011

During recent years, prices paid for oil and natural gas have fluctuated significantly. Estimated discounted future net cash flows in the table above for December 31, 2013, 2012 and 2011 were computed using NYMEX prices of $96.90, $94.68, and $95.84 per barrel of oil, and $3.67, $2.76, and $4.15 per MMBTU of natural gas, respectively.

The following table sets forth the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas liquids reserves for the period indicated.

Changes in Standardized Measure

	(in thousands)
Balance at December 31, 2010	$ 628,027
Sales of oil and natural gas liquids produced, net	(128,674)
Net changes in prices and production costs	156,678
Net changes in future development costs	(26,755)
Revisions of previous quantity estimates	97,372
Previously estimated development costs incurred	28,458
Accretion of discount	93,083
Changes in timing and other	25,180
Balance at December 31, 2011	$ 873,369
Sales of oil and natural gas liquids produced, net	(117,480)
Net changes in prices and production costs	(29,259)
Net changes in future development costs	(22,330)
Revisions of previous quantity estimates	14,678
Previously estimated development costs incurred	40,490
Accretion of discount	106,533
Changes in timing and other	(42,702)
Balance at December 31, 2012	$ 823,299
Sales of oil and natural gas liquids produced, net	(106,519)
Net changes in prices and production costs	63,290
Net changes in future development costs	(7,957)
Revisions of previous quantity estimates	11,919
Previously estimated development costs incurred	30,858
Accretion of discount	78,857
Changes in timing and other	(58)

Balance at December 31, 2013	$ 893,689

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Appendix A

GLOSSARY OF OIL AND NATURAL GAS TERMS

The terms defined in this section are used throughout this prospectus:

Analogous Reservoir: Analogous reservoirs, as used in resource assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

Basin: A large depression on the earth s surface in which sediments accumulate.

Bbl: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf: One billion cubic feet of natural gas.

Bcfe: One billion cubic feet of natural gas equivalent.

Boe: One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

Btu: One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Developed Acreage: The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Well: A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential: An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Economically Producible: The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. For this determination, the value of the products that generate revenue are determined at the terminal point of oil and natural gas producing activities.

Estimated Ultimate Recovery (EUR): Estimated ultimate recovery is the sum of proved reserves remaining as of a given date and cumulative production as of that date.

Exploitation: A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploratory Well: A well drilled to find and produce oil and natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Field: An area consisting of a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Gross Acres or Gross Wells: The total acres or wells, as the case may be, in which we have working interest.

ICE: Inter-Continental Exchange.

MBtu/d: One thousand Btu per day.

Mcf: One thousand cubic feet of natural gas.

MMBtu: One million British thermal units.

MMcf: One million cubic feet of natural gas.

MMcfe: One million cubic feet of natural gas equivalent.

Net Acres or Net Wells: Gross acres or wells, as the case may be, multiplied by our working interest ownership percentage.

Net Production: Production that is owned by us less royalties and production due others.

Net Revenue Interest: A working interest owner s gross working interest in production less the royalty, overriding royalty, production payment and net profits interests.

NGLs: The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX: New York Mercantile Exchange.

Oil: Oil and condensate.

Operator: The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

Play: A geographic area with hydrocarbon potential.

Possible Reserves: Reserves that are less certain to be recovered than probable reserves.

Probable Reserves: Reserves that are less certain to be recovered than proved reserves but that, together with proved reserves, are as likely as not to be recovered.

Productive Well: A well that produces commercial quantities of hydrocarbons, exclusive of its capacity to produce at a reasonable rate of return.

Proved Developed Reserves: Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

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Proved Reserves: Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration, unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price used is the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PUDs: Proved Undeveloped Reserves.

Proved Undeveloped Reserves: Proved oil and natural gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Realized Price: The cash market price less all expected quality, transportation and demand adjustments.

Recompletion: The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reliable Technology: Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserve Life: A measure of the productive life of an oil and natural gas property or a group of properties, expressed in years. Reserve life is calculated by dividing proved reserve volumes at year-end by production volumes. In our calculation of reserve life, production volumes are adjusted, if necessary, to reflect property acquisitions and dispositions.

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Reserves: Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reservoir: A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Resources: Resources are quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.

Spacing: The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.

Undeveloped Acreage: Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Wellbore: The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

Working Interest: An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

WTI: West Texas Intermediate.

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Appendix B-1

April 3, 2014

Mr. John A. Weinzierl

Memorial Resource Development LLC

1301 McKinney Street, Suite 2100

Houston, Texas 77010

Dear Mr. Weinzierl:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2013, to the Memorial Resource Development LLC (MRD) interest in certain oil and gas properties located in Colorado, Louisiana, Oklahoma, Texas, and Wyoming. Memorial Resource Development LLC owns its interest in these properties through its subsidiaries Black Diamond Minerals, LLC; Classic Hydrocarbons, Inc. (Classic IV); and WildHorse Resources, LLC (WHR). The WHR portion of the MRD interest shown herein comprises the WHR interest owned by MRD as of December 31, 2013, and the NGP Income Co-Investment Opportunities Fund II, LP interest managed by WHR. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by MRD (other than those attributable to BlueStone Natural Resources Holdings, LLC; Memorial Production Partners LP; and their respective subsidiaries). The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Memorial Resource Development LLC s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the MRD interest in these properties, as of December 31, 2013, to be:

Category	Net Reserves Oil (MBBL)	NGL (MBBL)	Gas(1) (MMCF)	Future Net Revenue (M$) Total	Present Worth at 10%
Proved Developed Producing	2,625.8	12,259.9	234,036.9	1,014,683.4	610,303.5
Proved Developed Non-Producing	776.9	1,644.9	29,760.0	159,150.0	92,615.4
Proved Undeveloped	7,907.9	28,671.9	538,457.1	1,608,681.2	766,033.0
Total Proved	11,310.5	42,576.7	802,254.1	2,782,514.7	1,468,952.1

Totals may not add because of rounding.

(1) Estimates of gas reserves include field fuel usage volumes for the WHR properties.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

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The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is MRD s share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for MRD s share of production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2013. For oil and NGL volumes, the average Southwestern Wyoming Sweet posted price of $83.53 per barrel is used for properties located in Natrona and Sweetwater Counties, Wyoming, and the average West Texas Intermediate posted price of $93.42 per barrel is used for all other properties. These average posted prices are adjusted by lease for quality and regional and local price differentials. For gas volumes, the average CIG Rocky Mountains spot price of $3.527 per MMBTU is used for properties located in Colorado and Wyoming, and the average Henry Hub spot price of $3.670 per MMBTU is used for all other properties. These average spot prices are adjusted by lease for energy content, transportation fees, and regional and local price differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $100.26 per barrel of oil, $39.72 per barrel of NGL, and $3.656 per MCF of gas.

Operating costs used in this report are based on operating expense records of MRD. For nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs, per-unit-of-production costs, and workover costs. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and MRD s estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by MRD and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the MRD interest. Therefore, our estimates of reserves and future revenue do not include

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adjustments for the settlement of any such imbalances; our projections are based on MRD receiving its net revenue interest share of estimated future gross production after field usage and shrinkage.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. For the Classic IV and WHR properties, a substantial portion of these reserves are for undeveloped locations and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from MRD, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III

C.H. (Scott) Rees III, P.E.

Chairman and Chief Executive Officer

By: /s/ Justin S. Hamilton

Justin S. Hamilton, P.E. 104999

Vice President

Date Signed: April 3, 2014

By: /s/ Allen E. Evans, Jr.

Allen E. Evans, Jr., P.G. 1286

Vice President

Date Signed: April 3, 2014

JSH:JLO

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DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standard5s Codification Topic 932, Extractive Activities Oil and Gas, and (3) the SEC s Compliance and Disclosure Interpretations.

(1) *Acquisition of properties*. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an analogous reservoir refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs*. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

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(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or G&G costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (oil and gas) in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a terminal point , which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves*. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with

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the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves*. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate*. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area*. The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves*. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties*. Properties with proved reserves.

(24) *Reasonable certainty*. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90%

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probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology*. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves*. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity s interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity s proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity s proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity s proved oil and gas reserves.

d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to *reflect the timing of the future net cash flows relating to proved oil and gas reserves.*

f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir*. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources*. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well*. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

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(30) *Stratigraphic test well*. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as exploratory type if not drilled in a known area or development type if drilled in a known area.

(31) *Undeveloped oil and gas reserves*. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC s Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

The company s level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);

The company s historical record at completing development of comparable long-term projects;

The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;

The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and

The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties*. Properties with no proved reserves.

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Appendix B-2

April 24, 2014

Mr. John A. Weinzierl

Memorial Resource Development LLC

1301 McKinney Street, Suite 2100

Houston, Texas 77010

Dear Mr. Weinzierl:

In accordance with your request, we have audited the estimates prepared by Memorial Resource Development LLC and its subsidiaries (collectively referred to herein as MRD), as of December 31, 2013, of the probable and possible reserves and future revenue to the Memorial Resource Development LLC interest in certain oil and gas properties located in Colorado, Louisiana, Oklahoma, and Texas. The audited estimates shown herein have been revised from the estimates in our April 4, 2014, audit letter to reflect changes in the development plan of the Upper Cotton Valley Sands in Terryville and Hico-Knowles Fields, Louisiana. With the exception of these changes, we completed our audit on or about April 4, 2014. Our estimates of proved reserves and future revenue for these properties are set forth in our report dated April 3, 2014. Memorial Resource Development LLC owns its interest in these properties through its subsidiaries Black Diamond Minerals, LLC; Classic Hydrocarbons, Inc.; and WildHorse Resources, LLC (WHR). It is our understanding that the probable and possible reserves estimated in this report constitute all of the probable and possible reserves owned by MRD (other than those attributable to BlueStone Natural Resources Holdings, LLC; Memorial Production Partners LP; and their respective subsidiaries). We have examined the estimates with respect to reserves quantities, reserves categorization, future producing rates, future net revenue, and the present value of such future net revenue, using the definitions set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Rule 4-10(a). The estimates of reserves and future revenue have been prepared in accordance with the definitions and regulations of the SEC and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas. This report has been prepared for Memorial Resource Development LLC s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The following table sets forth MRD s estimates of the net reserves and future net revenue, as of December 31, 2013, for the audited properties:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas(1) (MMCF)	Total	Present Worth at 10%
Probable	10,479.7	33,708.9	535,185.3	2,148,275.7	1,052,242.6
Possible	36,376.1	68,686.1	1,080,539.7	6,167,918.1	2,386,228.2

(1) Estimates of gas reserves include field fuel usage volumes for the WHR properties.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

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When compared on a field-by-field basis, some of the estimates of MRD are greater and some are less than the estimates of Netherland, Sewell & Associates, Inc. (NSAI). However, in our opinion the estimates of MRD s probable and possible reserves and future revenue shown herein are, in the aggregate, reasonable and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Additionally, these estimates are within the recommended 10 percent tolerance threshold set forth in the SPE Standards. We are satisfied with the methods and procedures used by MRD in preparing the December 31, 2013, estimates of reserves and future revenue, and we saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by MRD.

The estimates shown herein are for probable and possible reserves; a substantial portion of these reserves are for undeveloped locations. MRD s estimates do not include any value for undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Prices used by MRD are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2013. For oil and NGL volumes, the average West Texas Intermediate posted price of $93.42 per barrel is adjusted by lease for quality and regional and local price differentials. For gas volumes, the average CIG Rocky Mountains spot price of $3.527 per MMBTU is used for properties located in Colorado, and the average Henry Hub spot price of $3.670 per MMBTU is used for all other properties. These average spot prices are adjusted by lease for energy content, transportation fees, and regional and local price differentials. All prices are held constant throughout the lives of the properties.

Operating costs used by MRD are based on historical operating expense records. For nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs, per-unit-of-production costs, and workover costs. Operating costs for the operated properties are limited to direct lease- and field-level costs and MRD s estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Capital costs used by MRD are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Operating costs and capital costs are not escalated for inflation. Estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, estimates of MRD and NSAI are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing these estimates.

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It should be understood that our audit does not constitute a complete reserves study of the audited oil and gas properties. Our audit consisted primarily of substantive testing, wherein we conducted a detailed review of all properties. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by MRD with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. Our audit did not include a review of MRD s overall reserves management processes and practices.

We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Supporting data documenting this audit, along with data provided by MRD, are on file in our office. The technical persons responsible for conducting this audit meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Philip S. (Scott) Frost
Philip S. (Scott) Frost, P.E. 88738
Senior Vice President

Date Signed: April 24, 2014

By: /s/ William J. Knights
William J. Knights, P.G. 1532
Vice President

Date Signed: April 24, 2014

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Appendix C

Chairman & CEO	Executive Committee
C.H. (Scott) Rees III	P. Scott Frost
President & COO	J. Carter Henson, Jr.
Danny D. Simmons	Dan Paul Smith
Executive VP	Joseph J. Spellman
G. Lance Binder	

October 28, 2014

Mr. John A. Weinzierl

Memorial Resource Development Corp.

500 Dallas Street, Suite 1800

Houston, Texas 77002

Dear Mr. Weinzierl:

In accordance with your request, we have estimated the proved reserves and future revenue, as of September 30, 2014, to the Memorial Resource Development Corp. (MRD) interest in certain oil and gas properties located in Terryville, Hico-Knowles, and Ruston Fields, Louisiana. MRD owns its interest in these properties through its wholly-owned subsidiary WildHorse Resources, LLC (WHR). The MRD interest shown herein comprises the MRD interest as of September 30, 2014, and includes the 7 percent overriding royalty interest MRD plans to convey to Terryville Mineral & Royalty Partners LP. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 71 percent of all proved reserves owned by MRD. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for MRD s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the MRD interest in these properties, as of September 30, 2014, to be:

Category	Net Reserves Oil (MBBL)	NGL (MBBL)	Gas(1) (MMCF)	Future Net Revenue (M$) Total	Present Worth at 10%
Proved Developed Producing	1,888.8	11,909.7	199,954.0	1,093,917.5	670,666.6
Proved Developed Non-Producing	572.7	1,572.2	24,790.1	150,981.5	85,209.8
Proved Undeveloped	5,700.9	21,135.5	367,909.7	1,511,364.6	808,410.7
Total Proved	8,162.3	34,617.4	592,653.7	2,756,264.0	1,564,287.2

Totals may not add because of rounding.

(1) Estimates of gas reserves include field fuel usage volumes.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

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Gross revenue is MRD s share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for MRD s share of production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period October 2013 through September 2014. For oil and NGL volumes, the average West Texas Intermediate posted price of $95.56 per barrel is adjusted by gas gatherer for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $4.236 per MMBTU is adjusted by gas gatherer for energy content, transportation fees, and regional price differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $102.85 per barrel of oil, $42.41 per barrel of NGL, and $4.293 per MCF of gas.

Operating costs used in this report are based on operating expense records of MRD. For nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs, per-unit-of-production costs, and workover costs. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and MRD s estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by MRD and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the MRD interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on MRD receiving its net revenue interest share of estimated future gross production after field usage and shrinkage.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the

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reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from MRD, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III

C.H. (Scott) Rees III, P.E.

Chairman and Chief Executive Officer

By: /s/ Philip S. (Scott) Frost	By: /s/ William J. Knights
Philip S. (Scott) Frost, P.E. 88738	William J. Knights, P.G. 1532
Senior Vice President	Vice President
Date Signed: October 28, 2014	Date Signed: October 28, 2014

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DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas, and (3) the SEC s Compliance and Disclosure Interpretations.

(1) *Acquisition of properties*. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an analogous reservoir refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves   Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves   Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs*.   Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project*.   A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or G&G costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (oil and gas) in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a terminal point , which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term saleable hydrocarbons means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves*. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that

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have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves*. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate*. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area*. The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves*. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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(23) *Proved properties*. Properties with proved reserves.

(24) *Reasonable certainty*. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology*. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves*. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity s interests in both of the following shall be disclosed as of the end of the year:

- a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
- b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

- a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity s proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
- b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
- c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity s proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity s proved oil and gas reserves.*
- d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*

f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir*. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources*. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

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DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(29) *Service well*. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well*. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as exploratory type if not drilled in a known area or development type if drilled in a known area.

(31) *Undeveloped oil and gas reserves*. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC s Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

The company s level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);

The company s historical record at completing development of comparable long-term projects;

The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;

The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and

The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

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(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties*. Properties with no proved reserves.

30,000,000 Shares

Common Stock

PROSPECTUS

November 12, 2014

Joint Book-Running Managers

Citigroup

Barclays

BofA Merrill Lynch

BMO Capital Markets

Goldman, Sachs & Co.

J.P. Morgan

Raymond James

RBC Capital Markets

Wells Fargo Securities

Co-Managers

Credit Suisse

Scotiabank / Howard Weil

Simmons & Company International

Stephens Inc.

Stifel

Wunderlich Securities

Credit Agricole CIB

Natixis